BORDER AIR QUALITY STRATEGY

Canada–United States Emissions Cap and Trading Feasibility Study

CANADA–UNITED STATES AIR QUALITY AGREEMENT

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American spelling is used throughout this report.

CANADA-UNITED STATES EMISSIONS CAP AND TRADING FEASIBILITY STUDY

TABLE OF CONTENTS

Executive Summary ix

Introduction xiii

Section A: Air Quality Context 1
- A.1 OVERVIEW 1
- A.2 SHARED AIR QUALITY PROBLEMS 3
- A.3 PRECURSOR EMISSIONS: SOURCES AND GEOGRAPHICAL DISTRIBUTION OF SO_2 AND NO_X 5
- A.4 SHARED SOURCE REGIONS 8
- A.5 SUMMARY 11
- A.6 REFERENCES 13

Section B: Legal Background 15
- B.1 UNITED STATES 15
- B.2 CANADA 28
- B.3 SUMMARY 29

Section C: Applicability 31
- C.1 OVERVIEW OF PRINCIPLES 31
- C.2 SO_2 AND NO_X SOURCES AND DISTRIBUTION OF FUEL TYPES 33
- C.3 EMISSION REDUCTION OPTIONS FOR SO_2 AND NO_X 38
- C.4 OPT-IN PROVISIONS 40
- C.5 SUMMARY 41
- C.6 REFERENCES 42

Section D: Emissions Monitoring and Reporting 45
- D.1 PRINCIPLES 45
- D.2 U.S. MONITORING AND REPORTING 46
- D.3 ENVIRONMENT CANADA'S PROTOCOL FOR CONTINUOUS EMISSION MONITORING SYSTEMS (REPORT EPS 1/PG/7) 61
- D.4 ANALYSIS 62
- D.5 SUMMARY 65
- D.6 REFERENCES 66

Section E: Allowances Use 67
- E.1 UNIT OF MEASUREMENT 67
- E.2 ALLOWANCE SERIALIZATION 67
- E.3 ALLOWANCE DISTRIBUTION 68
- E.4 ALLOCATION TIMING 71
- E.5 BANKING 71
- E.6 BORROWING 71
- E.7 PROPERTY RIGHTS 71
- E.8 TRANSPARENCY 72
- E.9 SET-ASIDES 72
- E.10 ALLOWANCE ACCOUNTING 73

E.11 TAX CONSEQUENCES 73
E.12 THE U.S. EXPERIENCE WITH ALLOWANCE USE 73
E.13 SUMMARY 77

Section F: Electronic Emissions Trading Registry: Data Systems for Tracking Allowances and Emissions 79
F.1 PRINCIPLES FOR DESIGNING AN ELECTRONIC REGISTRY 79
F.2 COMPONENTS OF THE REGISTRY 80
F.3 CENTRALIZATION 81
F.4 THE U.S. EXPERIENCE WITH DATA TRACKING SYSTEMS 82
F.5 THE CANADIAN EXPERIENCE WITH DATA TRACKING SYSTEMS 85
F.6 SUMMARY 85

Section G: Compliance and Enforcement 87
G.1 OVERVIEW OF COMPLIANCE 87
G.2 ENFORCEMENT 88
G.3 THE U.S. EXPERIENCE WITH COMPLIANCE AND ENFORCEMENT 89
G.4 COMPLIANCE AND ENFORCEMENT IN CANADA 91
G.5 SUMMARY 91

Section H: Analytical Tool Development and Feasibility Analysis 93
H.1 DEVELOPMENT AND DESCRIPTION OF JOINT ANALYTICAL TOOLS 93
H.2 ILLUSTRATIVE MODELING SCENARIOS FOR CROSS-BORDER SO_2 AND NO_X EMISSIONS CAP AND TRADING 100
H.3 RESULTS FOR THE POWER SECTOR USING THE INTEGRATED PLANNING MODEL 101
H.4 RESULTS FROM AIR QUALITY MODELING 108
H.5 SUMMARY OF FEASIBILITY ANALYSIS AND TOOL DEVELOPMENT 114
H.6 REFERENCES 114

LIST OF TABLES

Table A-1 Average Concentration and Percent Concentration of $PM_{2.5}$ Mass from Selected State Contributions to Class 1 Areas (Acadia, Boundary Waters, Dolly Sods) 10

Table D-1 Essential Measurements Required by U.S. Emission Cap and Trading Programs 46

Table D-2 Part 75 Monitoring Options 48

Table D-3 CEMS Requirements for U.S. Emission Cap and Trade Programs 49

Table D-4 Low Mass Emission Units 51

Table D-5 Part 75 Certification Tests 54

Table D-6 Ongoing QA Test Requirements for Year-Round Reporters 56

Table E-1 Overview of Allowance Use in U.S. SO_2 and NO_x Programs 74

Table F-1 Required Emission Data on a Quarterly Basis 83

Table H-1 Exisiting U.S. and Canadian Electricity Generating Capacity by Source 96

Table H-2 Figures Demonstrating Projected Changes in Environmental Endpoints from Air Quality Modeling of an Illustrative U.S.-Canada Cross-Border Emissions Cap and Trade Scenario 99

Table H-3 Illustrative Emission Caps for the United States and Canada 101

LIST OF FIGURES

Figure A-1 Mean $PM_{2.5}$ Concentrations ($\mu g/m^3$) at Canadian Dichotomous Monitors and U.S. Federal Reference Monitors in the Border Region, 2000-2003 4

Figure A-2 Ozone Concentrations (ppb) in the U.S.-Canada Border Regions, 2000-2002 (Average Annual Fourth-Highest Daily Maximum Eight-Hour Ozone) 4

Figure A-3 Average Wet Sulfate Deposition, 1990-1994 5

Figure A-4 Annual Wet Sulfate Deposition, 2002 5

Figure A-5 Average Wet Nitrate Deposition, 1990-1994 6

Figure A-6 Annual Wet Nitrate Deposition, 2002 6

Figure A-7 Canada (2000) – U.S. (2001) Geographical Distribution of SO_2 Emissions 7

Figure A-8 Canada (2000) – U.S. (2001) Geographical Distribution of NO_X Emissions 7

Figure A-9 U.S. and Canadian National Emissions by Sector for SO_2 and NO_X, 2002 8

Figure A-10 Combined QTBA Plot Derived Using 2000 and 2001 $PM_{2.5}$ Measurements for the Warm Months (May-September) 9

Figure A-11 Average Concentrations ($\mu g/m^3$) of $PM_{2.5}$ and Components by State and Province 9

Figure A-12 Satellite Imagery of the Quebec Forest Fire PM Episode in July 2002 12

Figure B-1 CAIR: Affected Region and Emission Caps 22

Figure C-1 Fraction of Electric Generation by Fuel Type 35

Figure C-2 Total Electricity Generation by Fuel Type, 2002 36

Figure D-1 Overview of Continuous Emission Monitoring under Part 75 47

Figure D-2 Monitoring System Certification Process 53

Figure F-1 Sample Feedback Quarterly Report Receipt and Status Code Information 83

Figure F-2 Allowance Reconciliation 84

Figure H-1 Electricity Generation in Canada and the United States, 2003 95

Figure H-2 IPM Inputs of U.S. and Canadian Fossil Fuel-Fired Power Plants Showing Locations and Characteristics of the Plants Used in IPM 95

Figure H-3 Map of the AURAMS Modeling Domain Used in the Feasibility Study 100

Figure H-4 Map of the CMAQ Modeling Domain Used for CAIR 100

Figure H-5 NO_X East and West Model Regions for Illustrative Analysis 102

Figure H-6 Annual SO_2 Emissions in 2010 and 2020, Comparing the Base Case (with no caps in Canada) with the Trading Scenario (with caps in Canada and cross-border trading) 102

Figure H-7 Annual NO_X Emissions in 2010 and 2020, Comparing the Base Case (with no caps in Canada) with the Trading Scenario (with caps in Canada and cross-border trading) 103

Figure H-8 Summer NO_X Emissions in 2010 and 2020, Comparing the Base Case (with no caps in Canada) with the Trading Scenario (with caps in Canada and cross-border trading) 103

Figure H-9 Emissions of SO_2 and NO_X from the U.S. Power Sector - Base Case, Clear Skies U.S., and the Trading Scenario 104

Figure H-10 Emissions of SO_2 and NO_X from the Canadian Power Sector - Base Case and the Trading Scenario 104

Figure H-11 Annual Incremental Costs to the Base Case for the U.S. Power Sector of Illustrative Trading Scenario 105

Figure H-12 Annual Incremental Costs to the Canadian Power Sector of Illustrative Trading Scenario 106

Figure H-13 U.S. Generation Mix - Base Case, Clear Skies U.S., and the Trading Scenario 107

Figure H-14 Canadian Generation Mix - Base Case and the Trading Scenario 107

Figure H-15 Percent Change in Annual Fine Particles with Emission Reductions under Illustrative Trading Scenario Compared to Base Case in 2010 (CMAQ) 109

Figure H-16 Percent Change in Annual Fine Particles with Emission Reductions under Illustrative Trading Scenario Compared to Base Case in 2020 (CMAQ) 109

Figure H-17 Absolute Change in Annual Fine Particles (ug/m^3) with Emission Reductions under Illustrative Trading Scenario Compared to the Base Case in 2020 (CMAQ) 110

Figure H-18 Absolute Difference in $PM_{2.5}$ Concentration ($\mu g/m^3$), Comparing Illustrative Trading Scenario to the Base Case during the Winter Episode for 2020 (AURAMS) 110

Figure H-19 Absolute Difference in $PM_{2.5}$ Concentration (ug/m^3), Comparing Illustrative Trading Scenario to the Base Case during the Summer Episode for 2020 (AURAMS) 111

Figure H-20 Absolute Difference between Illustrative Trading Scenario to the Base Case for Ground Level Ozone Daily Maximum (ppb) during the Summer Episode for 2020 (AURAMS) 111

Figure H-21 Percent Change in Sulfur Deposition with Emission Reductions under Illustrative Trading Scenario Compared to Base Case in 2020 (CMAQ) 112

Figure H-22 Percent Change in Nitrogen Deposition with Emission Reductions under Illustrative Trading Scenario Compared to Base Case in 2020 (CMAQ) 112

Figure H-23 Absolute Change in Visibility (Deciviews) with Emission Reductions under Illustrative Trading Scenario Compared to Base Case in 2020 (CMAQ) 113

EXECUTIVE SUMMARY

The 1991 Canada-United States Air Quality Agreement established a flexible framework to address transboundary air pollution. In June 2003, Canada and the United States undertook three two-year joint projects, one of which is the feasibility of developing a cross-border cap and trade program for sulfur dioxide (SO_2) and nitrogen oxides (NO_X) emissions, emissions that are key components of fine particles, smog, regional haze, and acid rain in the transboundary region.

U.S. EPA and Environment Canada reviewed the key components of the U.S. cap and trade programs and developed Canada-U.S. economic and air quality modeling tools to be able to assess the potential economic and environmental impacts of NO_X and SO_2 cross-border trading.

The focus of the cross-border feasibility study has been electricity generators that burn fossil fuels and emit NO_X and SO_2 in the United States and Canada. Currently, over 3800 electricity generating units (EGUs) in the United States participate in the national SO_2 emissions cap and trade program (the Acid Rain Program), while over 2600 EGUs and large industrial boilers participate in the regional summer season NO_X emissions cap and trade program. Since its implementation in 1995, the U.S. Acid Rain Program has successfully reduced SO_2 emissions by 32 percent from 1990 levels, while electricity generation has increased by 30 percent over that same time period. Facilities have achieved their emission reduction requirements at substantially less cost, because the trading mechanism provides flexibility for sources to pursue the least-cost options. At the same time, mandatory emission caps have created the impetus for innovation in pollution abatement technologies and ensured the required reductions. Finally, the U.S. emission cap and trade programs, through their requirements for rigorous emission monitoring and reporting, as well as strong enforcement, have assured both high compliance and the integrity of the allowance markets.

There are several key findings in this report.

- The United States and Canada share three principal transboundary air quality problems: fine particulate matter ($PM_{2.5}$), ground-level or tropospheric ozone (O_3), and acid deposition. SO_2 and NO_X are key precursors that can lead to the formation of $PM_{2.5}$, ozone (or smog), and acid deposition in both countries. (See Ground-Level Ozone: Occurrence and Transport in Eastern North America and Transboundary PM Science Assessment at **http://www.epa.gov/airmarkets.usca/ index.html** or **http://www.ec.gc.ca/cleanair-airpur/key_positions_on_issues_of_concern-WS0A8790BD-1_En.htm** and **http://www.msc-smc.ec.gc.ca/saib/smog/transboundary/index_e.html**).

  A significant portion of the population in the eastern border region of both Canada and the United States is exposed to harmful levels of air pollutants, levels that often exceed both countries' air quality standards designed to protect human health. Acidic deposition remains at levels that cause concern for sensitive ecosystems in both countries, and significant degradation of visibility in national parks persists. Further emission reductions would improve air quality and reduce acid deposition in both countries, and an emissions cap and trading program can maintain those improvements at costs lower than traditional regulatory approaches.

- The legal framework in Canada and the United States was assessed for differences and gaps that would need to be addressed in order for there to be a cross-border emissions cap and trading program. In both countries, federal and provincial/state governments have legal responsibilities for air quality management and would need to participate in the development of any cross-border trading programs. While legal authorities exist now in Canada that could provide the basis for developing cross-border trading, additional clarification is needed in the United States. In both countries, legislative and/or regulatory changes would be needed to ensure that the units of trade—the "allowances"—issued by each country would be equivalent so that they could be recognized, traded, tracked, and used for compliance in either country. In addition, while cap and trade programs in the United States exist now, in Canada regulations would be required to create the mandatory emission reduction caps as well as the basis for cross-border trading, such as monitoring and reporting.

- Over 4000 units currently participate in the established cap and trade programs in the U.S. There are 207 Canadian fossil fuel-fired electricity generating units, in total, in Canada that are 25 MWe or larger and, therefore, similar to the universe of sources covered by the U.S. cap and trade programs. Two critical factors in assessing which sectors are best able to take part in cap and trade programs are, first, the sector's contribution to the emissions that must be reduced to address fine particles, acid rain, and ground-level ozone and, second, the ability to rigorously monitor the emissions from the sectors. Emissions monitoring equipment is available and being used by each of the sources in the U.S. cap and trade programs. Electricity generators that burn fossil fuels would be the best candidates for participating in possible future cross-border cap and trade programs. However, exploring the inclusion of key contributors (e.g., base metals smelters) from other sectors in Canada is recommended.
- In a cross-border cap and trade program that would "dovetail" with the existing U.S. SO_2 and NO_X cap and trade programs, the emission monitoring and reporting systems would need to be the same in both countries. Within an emissions cap and trading regime, the monitoring and reporting requirements provide the basis for guaranteeing the emission value of the allowances which can therefore be traded and used for compliance with full confidence. In the United States, emission monitoring and reporting requirements for the SO_2 and NO_X cap and trade programs are detailed in federal regulation (40 CFR Part 75) with which all affected sources must comply throughout the country. In Canada, provincial governments have traditionally addressed requirements for monitoring of emissions from electricity generator smokestacks, and the federal government has guidelines that some provinces have reflected in their requirements.
- For cross-border trading to be successful, certain trading rules should be the same in both countries. With respect to allowances, for instance, how allowances are identified by serial number, whether the allowances are measured in metric or imperial units, how allowances can be saved for future use or "banked," whether governments define allowances as "property rights," and the fungibility of allowances—the ability to freely exchange allowances—would need to be addressed and agreements reached. In the U.S. SO_2 and NO_X cap and trade programs, every allowance, regardless of its origin or destination, is deemed to have the same value, with the result that trades can occur without government approval and, therefore, can take place quickly—even online. Experience in the United States has shown that, with hundreds of sources participating, air quality concerns related to the distance and direction of trades have been adequately addressed with aggressive emission reduction caps and ongoing environmental assessments.
- In cross-border trading, other rules related to allowances could be handled differently in each jurisdiction. For example, in the U.S. NO_X SIP call program, while the federal government establishes an emissions "budget" for each state and provides a "model rule" as guidance, each state can

use its own method to distribute the state's budget of allowances to the EGUs and industrial boilers. Each state also defines the number of allowances that could be "set aside" from the cap for new sources or to encourage certain kinds of renewable or energy efficiency development. Such flexibility provides the opportunity for each jurisdiction to meet the emission cap requirements while allocating the cap among affected sources in ways that support jurisdictional goals.

- In cross-border trading, the requirements for verifying the emissions and allowance information and its reporting and tracking in online electronic registries in each country would have to be equivalent to provide for "borderless" transactions. Online electronic emissions and allowance tracking systems compile the information that is used by governments to determine compliance by facilities. The tracking systems also provide for public transparency so that full information about allowances traded and facility emissions is both robust and available.
- In a cross-border cap and trade program, while Canadian and U.S. sources would continue to be subject to their own domestic laws, harmonized compliance and enforcement would be essential. Among the features that would require harmonization would be the tests for what is "in" or "out" of compliance with respect to caps, emissions monitoring, reporting, and verification. Where compliance with the caps is concerned, the same compliance schedules would be essential to prevent undesirable trading behavior in the cross-border market. Further, minimum penalties for noncompliance with the caps would need to be equivalent in both countries. In the U.S. cap and trade programs, automatic penalties for noncompliance with the cap are sufficiently severe that compliance has been almost 100 percent since the programs began operating in the mid-1990s.

There are two key conclusions in this feasibility study.

- First, while the feasibility study demonstrates through air quality modeling that a cross-border NO_X and SO_2 emissions cap and trading program can reduce the total loading of pollutants into the environment over a broad geographic area, it is the levels and timing of the SO_2 and NO_X emission reduction requirements, or caps, in the electricity sector that determine the level and extent of the air quality and environmental benefits that would result. Trading does not alter the overall level of the emission reductions and consequent benefits.
- Second, the feasibility study used economic modeling to examine cost-effectiveness for the electricity sector of achieving emission reductions with a cross-border cap and trading program in place. The results mirror those seen in the United States, where the NO_X and SO_2 cap and trade programs have set emission reduction caps for electricity generators and provided the sources the opportunity to trade. Faced with mandatory requirements to reduce emissions of SO_2 and NO_X, the sources in the U.S. cap and trade programs have found that achievement of their reductions is cheaper with a system that allows trading than without.

Based on the analysis that Canada and the United States have done to date, a cross-border emissions cap and trade program could be feasible but the following critical program elements would be necessary:

- In Canada, enforceable SO_2 and NO_X emission caps for the electricity sector—and other sectors, as appropriate—that are comparable in stringency to emission reduction requirements in the U.S.
- A commitment by the United States and Canada, including provinces, to pursue implementation of cross-border SO_2 and NO_X cap and trade.

- In both countries, legislative and/or regulatory changes to give the allowances in each country equivalency so that they could be traded freely and used for compliance in either country.
- Development in Canada of the regulations that would provide the basis for cross-border trading and in particular the emissions monitoring and reporting requirements for electricity generating units, as well as development of the electronic tracking systems for emissions and allowances.

Recommendations for future work include:

- Conduct more comprehensive modeling of caps based on various policy considerations.
- Develop additional quality assurance of all data and, from Canada, improved historical emission inventories from the non-EGU sector for modeling assessments.
- Perform integrated assessments of alternative cap and trade scenarios, such as cost/benefit, air quality, health, and ecosystem impact analyses.
- Examine further the potential of including Canadian base metals smelters and boilers in industries such as cement kilns, petroleum refineries, chemical manufacturers, and pulp and paper mills in cap and trade programs.

INTRODUCTION

In June 2003, the Administrator of the U.S. Environmental Protection Agency and the Canadian Minister of the Environment announced three joint projects to be implemented under a Canada-United States Border Air Quality Strategy (BAQS). Identification of the joint projects fulfilled a pledge made by the two countries in January 2003 to build on the continued success of the 1991 Canada-United States Air Quality Agreement (AQA).

These projects were intended to explore opportunities for coordinated air quality management that could result in air quality improvements and the establishment of innovative strategies. One of the projects is this feasibility study, a binational project to jointly analyze the feasibility of cross-border trading of capped emissions of nitrogen oxides (NO_X) and sulfur dioxide (SO_2). This builds on the earlier commitment under the AQA to cooperate and exchange information with respect to market-based mechanisms, including emissions trading.

The goals of this project have been to examine key requirements and components of a SO_2 and NO_X emissions cap and trade program necessary to assess the feasbility of cross-border trading. By using illustrative scenarios, we can begin to understand the economic and environmental impacts of cross-border trading. Objectives of this feasability study are to:

- Develop analytical tools and share data to help evaluate a cross-border emissions cap and trade approach for addressing transboundary air quality issues;
- Analyze compliance regimes and identify any divergences in accountability frameworks (such as divergences and gaps in measuring, monitoring, tracking, and reporting air emissions in each country); and
- Describe the legal and regulatory infrastructure pertaining to NO_X and SO_2 emissions cap and trading regimes in each country.

For instance, an important gap that was recognized early in the study was the fact that, in Canada, emission caps for the electricity power sector—the key sector that participates in the U.S. cap and trade programs—only exist in parts of Ontario and Quebec, and only for NO_X emissions. Further, no emission cap and trading programs exist. While this study looks closely at the requirements of an emissions cap and trading program, the study's mandate did not include discussion of the cap level; hence the study does not attempt to address an appropriate level and timing of emission caps for Canada.

The first part of the study (Sections A through G) addresses key issues regarding feasibility and describes similarities and differences between Canada and the U.S. The second part of the study (Section H) uses emission and air quality models to demonstrate the feasibility of analyzing illustrative emission management scenarios. The study does not consider the appropriate level or timing of emission caps, nor does it look at pollutants other than SO_2 and NO_X.

The study has been carried out by federal teams of experts from both Canada and the United States, and information on the study has been provided in both countries through information sessions and reports to the U.S.-Canada Air Quality Committee, as well as other interested groups.

SECTION A
AIR QUALITY CONTEXT

This section examines regional air quality along the U.S.-Canada border and the role played by long-range transport. The section seeks to answer a primary question: What does the science indicate about the transboundary nature of particulate matter (PM), ozone, and their precursors that may provide additional insight into the feasibility of a cross-border SO_2 and NO_X emissions cap and trading program?

An emissions cap and trading program can reduce the total loading of pollutants into the atmosphere, particularly if these pollutants are emitted by many sources and transported over a large geographic region. Emission cap and trading programs in the United States have helped address ambient air quality problems by reducing background levels of pollution that contribute to adverse air quality. This section begins to assess the regional air quality problem along the U.S.-Canada border, giving consideration to the contributing meteorological conditions and chemical mixing in the atmosphere, by looking at existing scientific evidence in the cross-border area.

The following discussion broadly explains the air quality information relevant to the U.S.-Canada transboundary region. Section A.1 provides an overview of the air quality problems shared by the United States and Canada. Section A.2 discusses the extent of the shared air quality problem, and Section A.3 addresses sources and geographic distribution of precursor emissions. Section A.4 describes shared source regions, and Section A.5 summarizes the section.

A.1 OVERVIEW

A.1.1 The Chemistry of the Atmosphere

The United States and Canada share three principal air quality problems: PM, tropospheric ozone, and acid deposition. Emissions of the precursor gases SO_2 and nitrogen oxide and nitrogen dioxide (collectively referred to as NO_X) are the primary contributors to poor air quality in eastern North America. Discussions regarding air quality in support of the feasibility of a cross-border emissions cap and trading program consider only the precursor gases SO_2 and NO_X, although it is recognized that volatile organic compounds (VOCs), ammonia (NH_3), and other components of ground-level ozone (e.g., black and organic carbon), or smog, can also contribute to poor air quality in the cross-border region.

When emitted into the atmosphere, the precursor gases SO_2 and NO_X can undergo chemical reactions to form secondary PM, ozone, regional haze, and acid rain. Ground-level ozone is a gas that forms when NO_X and VOCs react with other chemicals in the air in the presence of sunlight. NO_X and VOCs are emitted by combustion sources; VOCs often originate from petrochemical operations (such as refueling stations), solvents, cleaners, and paints.

SO_2 and NO_X, primarily from anthropogenic sources, are also key contributors to acid deposition and fine particle ($PM_{2.5}$) formation. These gases remain in the atmosphere under appropriate meteorological conditions, influencing the air quality over a large receptor region. When SO_2 and NO_X are emitted into the atmosphere, they can form "aerosols," consisting of liquid and solid particles. When the amount of humidity (i.e., water) in the air becomes sufficiently high, aerosols containing SO_2 and NO_X react with water to form acidic compounds, falling to the earth as acid deposition. (For a more thorough description of atmospheric chemistry and related meteorological theories, see the references included at the end of this section.)

SO_2 and NO_X emissions are key targets of air quality management in the border region and have been successfully reduced through comprehensive emission reduction programs in both countries. In the United States, a number of programs have been in place over the past

35 years that have reduced both SO_2 and NO_X. In particular, a large-scale SO_2 emissions cap and trading program for electricity generating sources has been in effect for 10 years under Title IV of the Clean Air Act to address acid rain. Canadian sources have also reduced emissions of these precursor gases over the past several decades, most recently through implementation of the Canada-wide Acid Rain Strategy for Post 2000. However, poor air quality continues to be documented in the shared border region between Canada and the United States, indicating that additional reductions are needed.

A.1.2 Environmental and Human Health Effects of Air Pollution

Significant harmful effects on human health and the environment result from elevated ambient levels of ozone and fine particles, including particle sulfate and particle nitrate. Reducing emissions of SO_2 and NO_X from power plants and other sources in turn reduces ambient levels of both $PM_{2.5}$ and ozone, benefiting human health and the environment.

Mounting epidemiological evidence published since 1990 suggests that all PM, especially $PM_{2.5}$, is harmful to human health. A large published body of literature now provides a strong basis for quantification of human mortality and morbidity reductions associated with reduced ambient levels of $PM_{2.5}$ as SO_2 and NO_X emissions are reduced (U.S. EPA, 2005). The benefits to human health from reductions of $PM_{2.5}$ include reductions in adult and infant mortality; fewer new cases of chronic bronchitis; prevention of nonfatal heart attacks, as well as fewer hospitalizations and emergency room visits for respiratory and cardiovascular illnesses; and fewer days when adults and children limit their outdoor activities.

The human health benefits of reducing ground-level ozone, independent of exposure to PM, include reductions of hospitalizations for respiratory conditions and fewer emergency room visits for asthma. Recent evidence suggests that short-term exposure to ozone may have a significant effect on daily mortality rates.

Just as $PM_{2.5}$ and ozone pollution adversely affect human health, $PM_{2.5}$ and ozone pollution adversely affect visibility and ecosystem health. $PM_{2.5}$ in the air absorbs and scatters light as it passes through the atmosphere, which creates a haze that reduces one's visual range and the clarity of viewed objects. When visibility is reduced, the value of a vacation day at a national park is reduced.

Air pollution in the form of sulfur and nitrogen deposition harms freshwater lakes and streams, coastal estuaries, and forests. Chronically and episodically acidified lakes and streams lose fish species, other aquatic life, and recreational and commercial fishing. Nitrogen deposition is a significant contributor to excess nitrogen in watersheds, causing eutrophication of estuaries. The environmental consequences of eutrophic estuaries include algal blooms and low levels of dissolved oxygen that stress or kill fish and shellfish, as well as reduce areas of submerged aquatic vegetation that provide important habitat for many species. In forests, acid deposition leaches nutrients from the leaves, needles, and soils, thus removing elements essential for tree growth. Also, acidification mobilizes aluminum in forest soils and thus interferes with nutrient uptake through the roots. Trees weakened by the burden of acid deposition are susceptible to disease, drought, and extreme temperatures. Ozone exposure also stresses trees, damages urban ornamental plants, and reduces the commercial yields of forests and agricultural crops. Canadian studies estimate that a 75 percent reduction in SO_2 emissions from Canadian and U.S. sources—beyond what is currently called for in the Canada-U.S. Air Quality Agreement—will be required to protect eastern Canadian and northeastern U.S. ecosystems from deposition damage (Environment Canada, 2004). In the United States, researchers have examined a range of 40 to 80 percent further reduction in emissions to more fully protect sensitive ecosystems (Bulger et al., 2000; Driscoll et al., 2001).

Acid deposition affects the built environment as well, damaging buildings, bridges, and historical monuments by eroding the surfaces of paint, galvanized steel, limestone, and marble. $PM_{2.5}$ deposition also causes soiling of buildings and monuments. Such material damage reduces the value and increases the costs for maintenance and repair of national infrastructure and significant historical sites.

Progress implementing current commitments under the Canada-U.S. Air Quality Agreement continues. However, both countries recognize that additional efforts are necessary to address ongoing public health and environmental problems (Canada–United States Air Quality Agreement Progress Report, 2004).

A.2 SHARED AIR QUALITY PROBLEMS

A.2.1 Observations of Ambient $PM_{2.5}$ Concentrations

Recent air quality monitoring data indicate that mean levels of $PM_{2.5}$ are as high as 18 micrograms per cubic meter (µg/m^3) in the northeastern United States but consistently lower than 12 µg/m^3 in the mid-continental states for the years 2000-2003 (see Figure A-1). The northeastern United States is a region of high ambient PM levels, with 98th-percentile values up to 65 µg/m^3 (the U.S. ambient air quality standard) at a majority of sites. Canadian locations exhibit generally lower levels of $PM_{2.5}$, although 98th-percentile concentrations greater than 30 µg/m^3 (the Canada-wide Standard) occurred in several regions of the country for the years 2000-2002, particularly in the Windsor-Quebec City corridor.

Current ambient levels of $PM_{2.5}$ in much of the border region exceed both Canadian and U.S. standards, affecting over 65 million people in the United States and 13 million Canadians. In the Georgia Basin—Puget Sound region, there are sites with elevated $PM_{2.5}$ levels (with very few sites exceeding either standard for the time periods evaluated), but the problem is more confined (subregional), and the levels are generally lower than in the northeast. Urban concentrations of $PM_{2.5}$ are higher than concentrations in rural sites in all regions of both Canada and the United States.

A.2.2 Observations of Ambient Ozone Concentrations

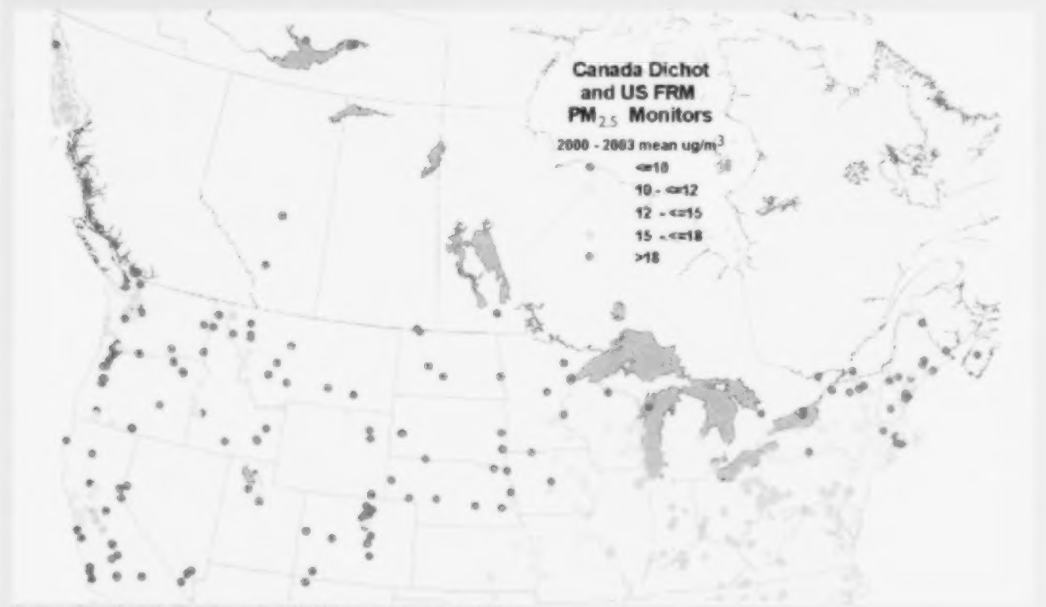
Regional $PM_{2.5}$ and ground-level ozone share common precursors and similar influences of transport and meteorology in eastern North America, with the highest concentrations of both occurring in the summer months.

Ambient ozone data have been examined at monitoring sites within 500 km of the Canada-U.S. border. Data meeting specific data completeness requirements were used to create the contour map presented in Figure A-2. This figure shows the annual fourth-highest daily maximum eight-hour ozone concentration averaged over the period 2000-2002 in Canada and the United States, the basis for determining compliance with the ozone standard (65 parts per billion (ppb) for Canada and 85 ppb for the United States). The highest values are found in the northeastern United States and southeastern Canada, while the lowest values are generally found in southern Manitoba and southern British Columbia near Vancouver. A large portion of the northeastern United States and southeastern Canada also exhibits levels in excess of domestic standards set for ozone in the respective countries.

A.2.3 Observations of Sulfate and Nitrate Deposition

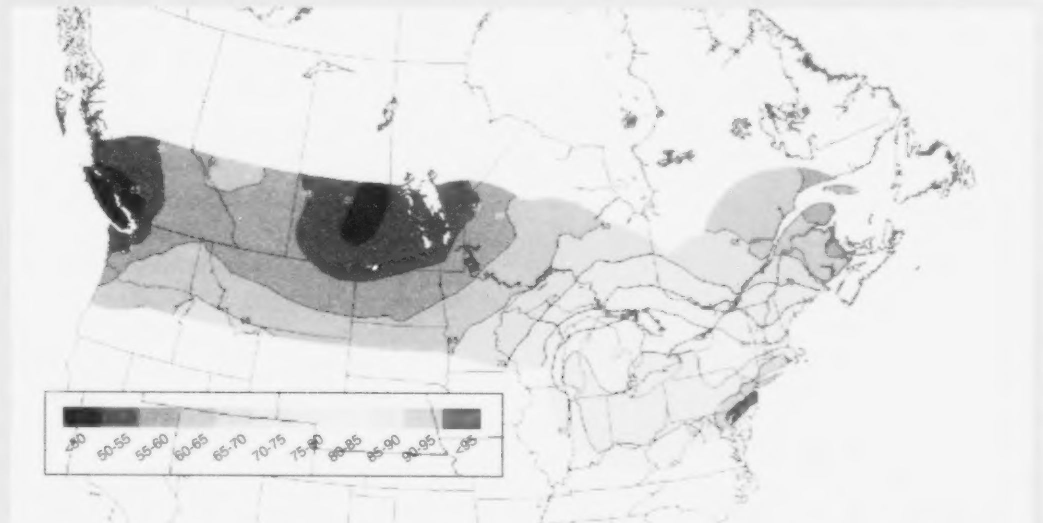
Although there have been marked reductions in sulfate and, to a lesser extent, nitrate concentrations, acidic deposition remains at levels that cause concern for sensitive ecosystems in both countries. Wet deposition is comparatively easy to measure using precipitation gauges and is regularly used

Figure A-1 Mean $PM_{2.5}$ Concentrations ($\mu g/m^3$) at Canadian Dichotomous Monitors and U.S. Federal Reference Monitors in the Border Region, 2000-2003


Canada Dichot
and US FRM
PM2.5 Monitors
2000 - 2003 mean ug/m3
<=10
10 - <=12
12 - <=15
15 - <=18
>18

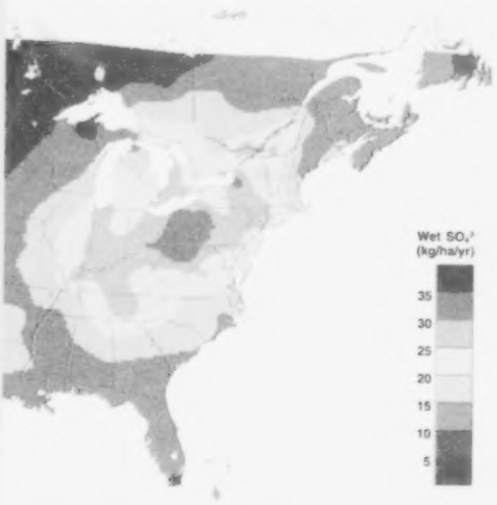
Source: Canada–U.S. Transboundary PM Science Assessment, 2004.

Figure A-2 Ozone Concentrations (ppb) in the U.S.-Canada Border Regions, 2000-2002 (Average Annual Fourth-Highest Daily Maximum Eight-Hour Ozone)


≤50
50-55
55-60
60-65
65-70
70-75
75-80
80-85
85-90
90-95
≥95

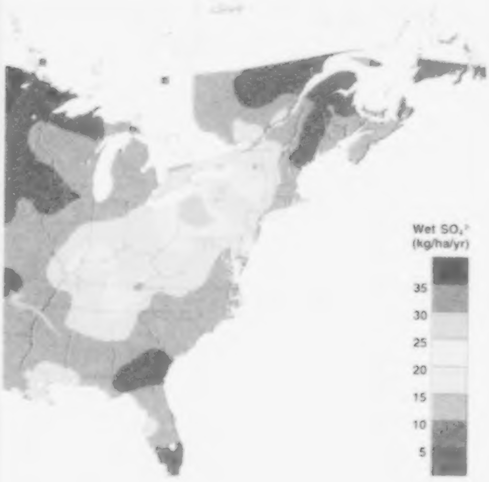
Source: Canada–United States Air Quality Agreement Progress Report, 2004.

Figure A-3 Average Wet Sulfate Deposition, 1990-1994



Source: Canada-United States Air Quality Agreement Progress Report, 2004.

Figure A-4 Annual Wet Sulfate Deposition, 2002



Source: Canada-United States Air Quality Agreement Progress Report, 2004.

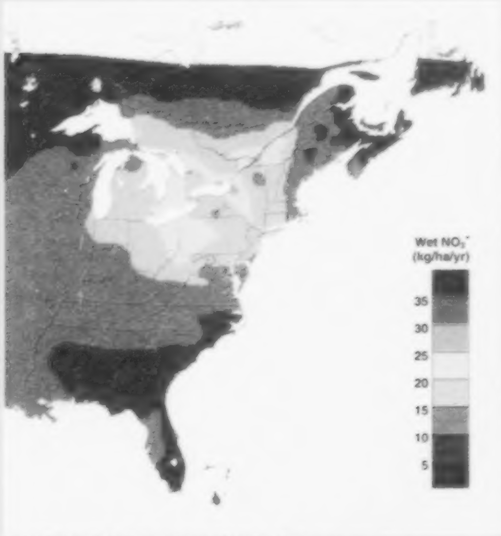
as the reference measure for comparison with emissions. On the other hand, the dry portion of deposition is difficult to measure directly; therefore, inferential models are used in conjunction with filter pack measurements of pollutant concentrations to estimate dry deposition. The combination of wet and dry deposition of sulfate and nitrate contributes to the acidification of ecosystems. Estimated sulfate and nitrate wet deposition data for the years 1990-1994 are illustrated in Figures A-3 and A-5, to be compared with sulfate and nitrate deposition data for 2002 in Figures A-4 and A-6. There has been a significant response to both the U.S. and Canadian Acid Rain Programs. A broad regional response to SO_2 emission reductions, in particular, is seen along the U.S.-Canada border. Wet sulfate deposition is greatest in eastern North America, along an axis running from the Mississippi River to the lower Great Lakes.

SO_2 emissions are estimated to have declined by a third to a half from 1990 levels, largely over the eastern half of North America. NO_X emissions have risen in Canada and have fallen slightly in the United States. Decreasing NH_3 emissions, where sulfate concentrations are high, can reduce $PM_{2.5}$ mass concentration, but may increase precipitation acidity. Trends in wet deposition of sulfate and nitrate correspond to changes in SO_2 and NO_X emissions (Environment Canada, 2004).

A.3 PRECURSOR EMISSIONS: SOURCES AND GEOGRAPHICAL DISTRIBUTION OF SO_2 AND NO_X

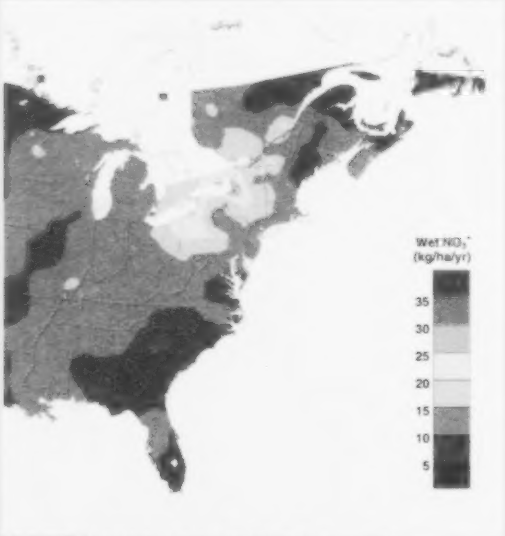
SO_2 and NO_X emissions are significant contributors to the shared air quality problems of the transboundary region in both Canada and the United States. The gaseous precursor emission distributions of NO_X and SO_2 largely follow population centers and result from intensive energy use, industrial activity, and transportation sources, also extending throughout the cross-border region in a wide area (see Figures A-7 and A-8). High SO_2 and NO_X emissions are located in the industrial Midwest, northeastern United States, and southern Ontario.

Figure A-5 Average Wet Nitrate Deposition, 1990-1994



Source: Canada-United States Air Quality Agreement Progress Report, 2004.

Figure A-6 Annual Wet Nitrate Deposition, 2002



Source: Canada-United States Air Quality Agreement Progress Report, 2004.

A.3.1 Sulfur Dioxide

Electricity generators contributed about 70 percent of SO_2 emissions in 2002 to the total national emissions in the United States, with some 95 percent of these emissions from coal combustion. In Canada, electricity generators contributed approximately 26 percent of SO_2 emissions to the total national emissions, with 86 percent of these emissions from coal combustion (Figure A-9). Non-ferrous mining and smelting are the main anthropogenic sources of SO_2 emissions in Canada, accounting for roughly 33 percent.

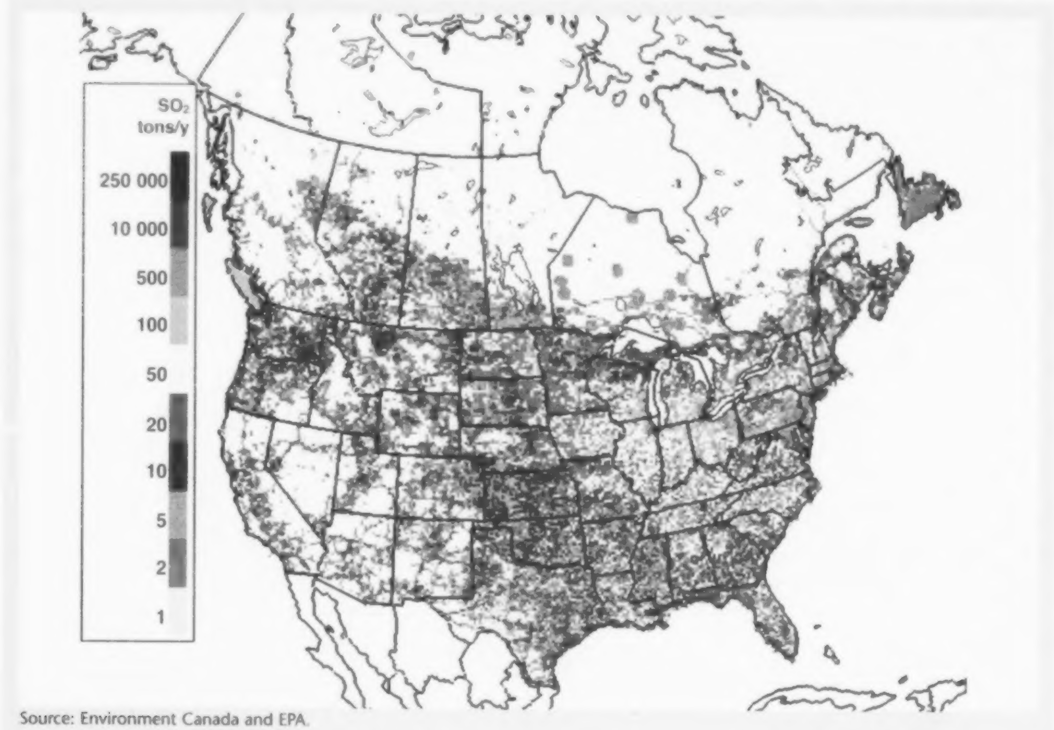
Overall, a 38 percent reduction in SO_2 emissions is projected in Canada and the United States from 1980 to 2010. In the United States, these reductions in SO_2 emissions are mainly a result of controls on electric utilities under the the Acid Rain Program (1990 Clean Air Act Amendments (CAAA), Title IV) and the Clean Air Interstate Rule (CAIR) and desulfurization of diesel fuel under Section 214 of the 1990 CAAA. In Canada, these reductions are primarily from actions in the non-ferrous mining and smelting sector and electric utilities as part of the Canada-wide Acid Rain Strategy. As demonstrated in recent reports and government findings, more reductions of SO_2 and NO_X emissions are needed on both sides of the border to lower background levels and transport of precursors and to more fully address the shared air quality problems (Canada-U.S. Air Quality Committee, 2004).

A.3.2 Nitrogen Oxides

The principal anthropogenic sources of NO_X emissions in North America remain the combustion of fuels in nonroad and on-road mobile sources and electricity generators. Motor vehicles, residential and commercial furnaces, industrial and electric utility boilers and engines, and other equipment contribute to this category. The power sector in the United States contributes roughly 22 percent of the total national emissions of NO_X; 87 percent of those NO_X emissions result from coal. In Canada, the power sector contributes 11 percent of total national NO_X emissions, of which 81 percent is from coal (Figure A-9).

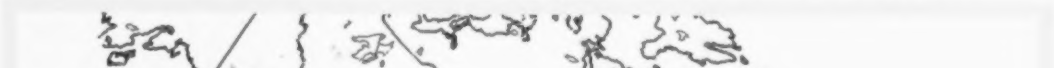
U.S. reductions in NO_X emissions are attributed to the estimated controls associated

Figure A-7 Canada (2000) - U.S. (2001) Geographical Distribution of SO_2 Emissions


SO2 tons/y
250 000
10 000
500
100
50
20
10
5
2
1

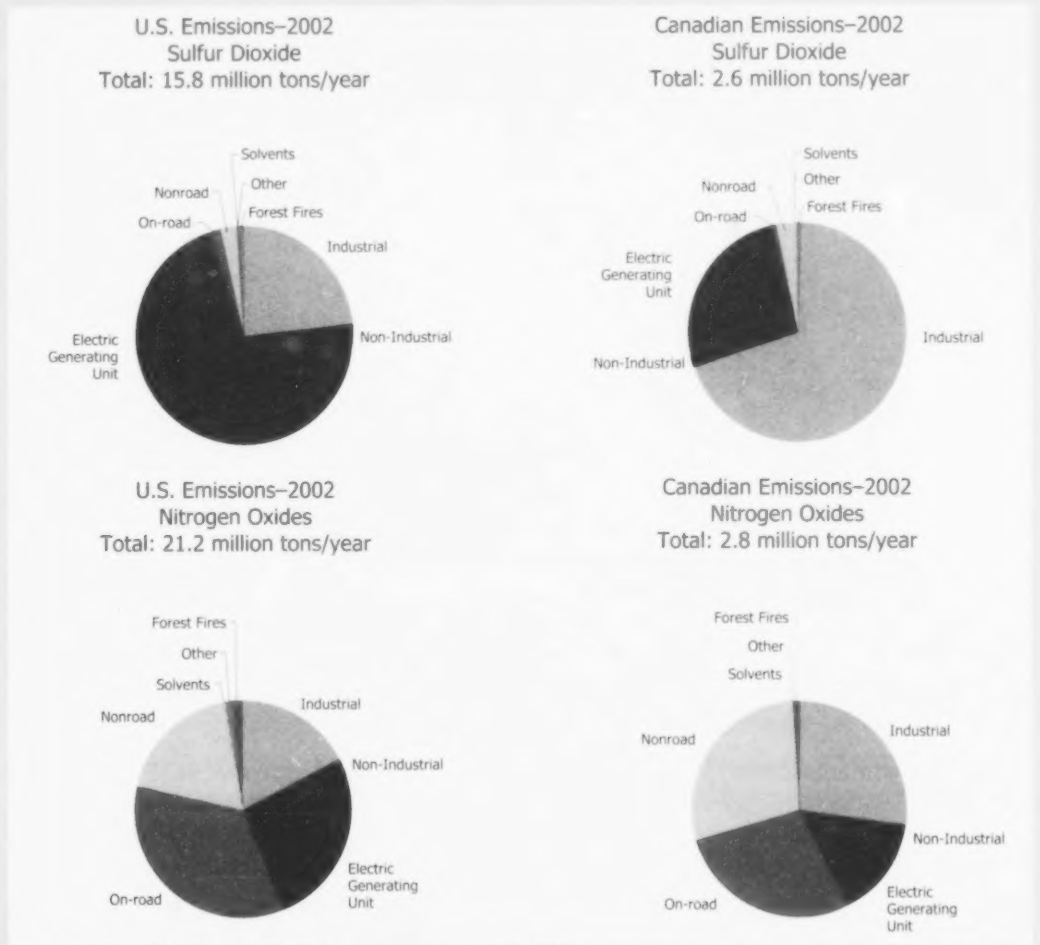
Source: Environment Canada and EPA.

Figure A-8 Canada (2000) - U.S. (2001) Geographical Distribution of NO_X Emissions


NOX tons/y
96 500
10 000
5 000
1 000
400
100
50
10
5
1

Source: Environment Canada and EPA.

Figure A-9 U.S. and Canadian National Emissions by Sector for SO_2 and NO_X, 2002



Source: Canada-United States Air Quality Agreement Progess Report, 2004.

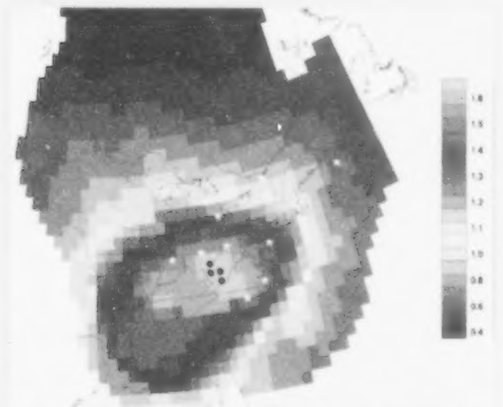
with the Tier 2 Tailpipe Standard, Heavy-Duty Engine and Vehicle Standards, and the Highway Diesel Fuel rules, as well as to controls in electric utilities under the Acid Rain Program and the regional efforts to address ozone transport, beginning with the Ozone Transport Commission NO_X Budget Program (1999) and the NO_X State Implementation Plan (SIP) call NO_X Budget Trading Program (2004) as well as the Clean Air Interstate Rule (2009).

In Canada, substantial NO_X emission reductions are expected to occur mainly as a result of the implementation of the Ozone Annex under the Canada-U.S. Air Quality Agreement, including the stationary source commitments for NO_X emissions and the 10-year vehicle and fuels agenda, which implements Tier 2 Tailpipe Standards, among other initiatives. However, recent research findings indicate more action may be warranted to solve the shared air quality problems.

A.4 SHARED SOURCE REGIONS

Observational evidence, in combination with emissions information and air quality model applications, has been used by both Canada and the United States to determine the source

Figure A-10 Combined QTBA Plot Derived Using 2000 and 2001 $PM_{2.5}$ Measurements for the Warm Months (May-September)

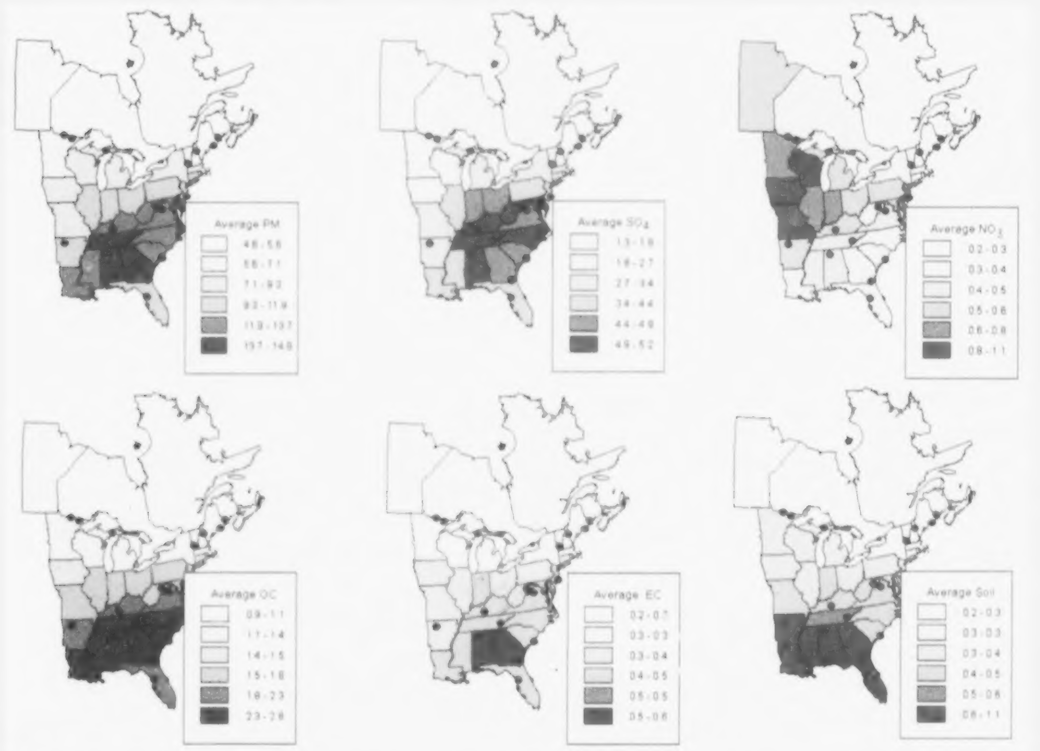


Source: Canada–United States Transboundary PM Science Assessment, 2004.

regions that contribute to poor air quality in the transboundary region. These scientific results have led to the notion of a borderless approach to air quality analysis and, ultimately, management, with sources and source regions of smog, fine particles, and acid deposition transcending geographic boundaries. The following scientific studies have been selected as evidence of this borderless approach, but these studies are by no means exhaustive. Additional analyses can be found in material provided in the reference section.

A type of source-receptor analysis known as Quantitative Transport Bias Analysis (QTBA) was applied to determine the geographic areas that contribute to above- and below-average fine particle mass ($PM_{2.5}$) over eastern

Figure A-11 Average Concentrations (µg/m³) of $PM_{2.5}$ and Components by State and Province (IMPROVE sites shown as blue dots)


Average PM
48-56
56-71
71-93
93-119
119-137
137-148
Average SO_4
13-18
18-27
27-34
34-44
44-49
49-52
Average NO_3
02-03
03-04
04-05
05-06
06-08
08-11
Average OC
09-11
11-14
14-15
15-18
18-23
23-28
Average EC
02-03
03-03
03-04
04-05
05-05
05-06
Average Soil
02-03
03-03
03-04
04-05
05-06
06-11

Each trajectory endpoint is associated with concentrations corresponding to the IMPROVE sample for the trajectory start date (Kenski, 2004). EC = elemental carbon, OC = organic carbon, SO_4 = sulfate, NO_3 = nitrate

Source: Canada–United States Transboundary PM Science Assessment, 2004.

Table A-1 Average Concentration and Percent Contribution of $PM_{2.5}$ Mass from Selected States to Class 1 Areas (Acadia, Boundary Waters, Dolly Sods)

Class 1 Area	**Acadia**		**Boundary Waters**		**Dolly Sods**	
State/ province	**Average $PM_{2.5}$ concentration (ug/m^3)**	**Annual percent $PM_{2.5}$ mass**	**Average $PM_{2.5}$ concentration (ug/m^3)**	**Annual percent $PM_{2.5}$ mass**	**Average $PM_{2.5}$ concentration (ug/m^3)**	**Annual percent $PM_{2.5}$ mass**
States						
Illinois	10.8	0.4	9.5	1.7	8.7	1.6
Indiana	17.1	0.9	12.5	0.6	11.0	3.2
Iowa	7.6	0.2	8.1	5.0	8.5	0.9
Kentucky	11.8	0.5			14.0	8.6
Maine	5.6	12.6			8.6	0.1
Michigan	7.6	1.7	6.2	1.7	10.1	2.6
Minnesota	7.1	0.6	5.7	35.2	8.6	1.0
New Hampshire	8.6	2.0				
New Jersey	18.9	1.0			8.4	0.1
New York	8.2	4.4			9.1	0.8
North Carolina	13.9	0.3	10.0	0.1	12.0	3.1
Ohio	10.6	1.2	12.8	0.2	11.5	8.8
Pennsylvania	13.2	3.0			10.9	5.1
Tennessee	9.9	0.2			13.4	4.9
Vermont	8.3	1.8				
Virginia	14.2	0.9			11.8	7.6
West Virginia	18.4	0.5	10.0	0.1	14.0	26.4
Wisconsin	6.2	0.6	7.1	7.6	9.0	1.3
Provinces						
Ontario	6.0	7.7	3.5	16.4	9.2	4.8
Quebec	4.9	17.8	2.4	0.2	6.6	0.7

Source: Canada-United States Transboundary PM Science Assessment, 2004.

North America (Figure A-10) (Canada-U.S. Transboundary PM Science Assessment, 2004). Source regions are shown with the area of most significant contribution indicated by the gray coloring, and the area of least significance to above-average concentrations indicated by the blue coloring (as per the legend). Receptor sites used for the analysis are shown as yellow stars, while the black circles indicate locations of the greatest predicted contribution to the receptors. Values greater than 1.0 indicate a high likelihood of air masses passing over that area, bringing above-average warm-season $PM_{2.5}$ to the receptor. Much of the populated area of northeastern Canada and the United States was implicated in the buildup of $PM_{2.5}$ to above-average concentrations. The significantly contributing area leading to above-average $PM_{2.5}$ levels at the receptor sites covers much of the eastern United States, as well as southern Ontario.

Speciated IMPROVE measurements for 17 Class 1 sites (represented by dots in Figure A-11) in the eastern United States were examined in an analysis (Kenski, 2004) at the Lake Michigan Air Directors Consortium. Three-day back-trajectories for these sites were calculated with each endpoint (one per hour, 72 per trajectory) associated with concentrations corresponding to IMPROVE samples for the trajectory start date. These concentrations are averaged by state and province, as shown in Figure A-11.

The data presented indicate which states are associated with high-concentration air masses arriving at Class 1 areas, but do not take into

Table A-1 Average Concentration and Percent Contribution of $PM_{2.5}$ Mass from Selected States to Class 1 Areas (Acadia, Boundary Waters, Dolly Sods)

Class 1 Area	**Acadia**		**Boundary Waters**		**Dolly Sods**	
State/ province	**Average $PM_{2.5}$ concentration (ug/m³)**	**Annual percent $PM_{2.5}$ mass**	**Average $PM_{2.5}$ concentration (ug/m³)**	**Annual percent $PM_{2.5}$ mass**	**Average $PM_{2.5}$ concentration (ug/m³)**	**Annual percent $PM_{2.5}$ mass**
States						
Illinois	10.8	0.4	9.5	1.7	8.7	1.6
Indiana	17.1	0.9	12.5	0.6	11.0	3.2
Iowa	7.6	0.2	8.1	5.0	8.5	0.9
Kentucky	11.8	0.5			14.0	8.6
Maine	5.6	12.6			8.6	0.1
Michigan	7.6	1.7	6.2	1.7	10.1	2.6
Minnesota	7.1	0.6	5.7	35.2	8.6	1.0
New Hampshire	8.6	2.0				
New Jersey	18.9	1.0			8.4	0.1
New York	8.2	4.4			9.1	0.8
North Carolina	13.9	0.3	10.0	0.1	12.0	3.1
Ohio	10.6	1.2	12.8	0.2	11.5	8.8
Pennsylvania	13.2	3.0			10.9	5.1
Tennessee	9.9	0.2			13.4	4.9
Vermont	8.3	1.8				
Virginia	14.2	0.9			11.8	7.6
West Virginia	18.4	0.5	10.0	0.1	14.0	26.4
Wisconsin	6.2	0.6	7.1	7.6	9.0	1.3
Provinces						
Ontario	6.0	7.7	3.5	16.4	9.2	4.8
Quebec	4.9	17.8	2.4	0.2	6.6	0.7

Source: Canada-United States Transboundary PM Science Assessment, 2004.

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The data presented indicate which states are associated with high-concentration air masses arriving at Class 1 areas, but do not take into account the frequency with which air masses traverse a particular area or state. States that are closer to Class 1 sites will tend to contribute more $PM_{2.5}$ to those sites, because the air masses spend more time over those nearby states and emissions from nearby sources have less time to disperse and deposit than emissions from sources farther away. These areas of more frequent transport can be associated with $PM_{2.5}$ concentrations that are high, low, or moderate. By combining this frequency information with the concentration information, this study derives an average contribution to $PM_{2.5}$ mass from each state/province to the Class 1 areas.

Table A-1 gives the average concentration and percent $PM_{2.5}$ mass contributed by selected states and provinces to a sample of the Class 1 areas examined. These results can be thought of as indicators combining the upwind status of a state/province, the geographic size of the state/province, and the magnitude of source emissions within the state/province. A state or province that is close to, and frequently upwind of, multiple Class 1 areas will generally contribute more mass than states or provinces that are seldom upwind, unless the concentration difference is marked. For example, Minnesota contributes a large percentage of mass to Boundary Waters (35.2 percent), although the average concentration associated with air masses in Minnesota is less than 6 µg/m³. Similarly, the Canadian provinces make significant contributions to the border-area Class 1 sites; Ontario provides about 16 percent of the annual $PM_{2.5}$ mass at Boundary Waters, and Quebec provides about 18 percent to Acadia. Ohio and Pennsylvania are associated with high-concentration air masses at the three Class 1 sites shown, but make significant (>5 percent) contributions to annual $PM_{2.5}$ mass only at the nearby Dolly Sods wilderness site.

In an analogous manner, the contribution of each state and province to the joint set of 17 Class 1 areas was derived (not shown). The results indicate that some states associated with high-concentration air masses nevertheless contribute only a small amount of mass to the collective group of Class 1 sites; conversely, states (or provinces) with low average concentrations can be major mass contributors (Kenski, 2004).

The Canada-U.S. Transboundary PM Science Assessment, completed and peer reviewed in 2004 under the Canada-U.S. Air Quality Agreement, found further evidence that emissions of SO_2 and NO_X from the northeastern United States and southern Canada have an impact on $PM_{2.5}$ levels in many areas of the two countries, including as far east as Nova Scotia and New Brunswick. Source-receptor analyses indicate that there are several areas that contribute to elevated PM levels in eastern North America. These areas include, but are not restricted to, the following:

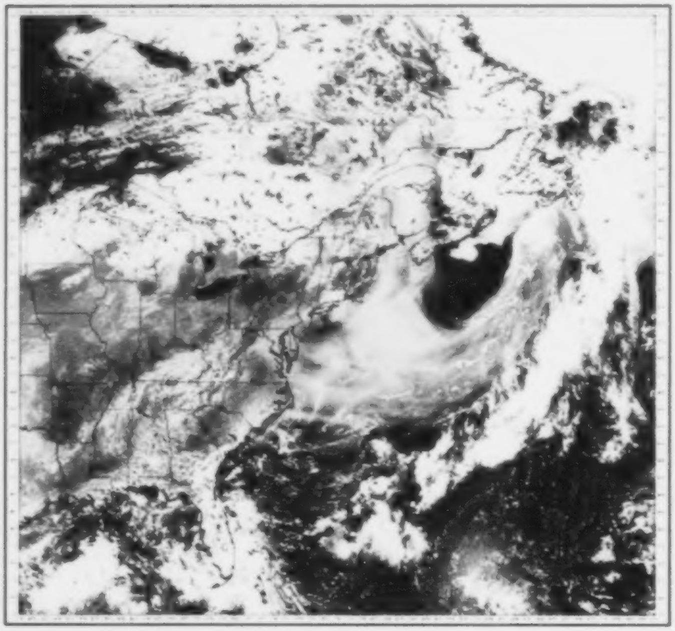
- Southeast Ohio to the western part of Virginia, and western Kentucky to central Tennessee
- Windsor-Quebec City corridor
- U.S. Midwest and Boston-to-Washington, D.C., corridor
- Ohio River Valley.

Additional evidence for cross-border flows of air masses comes from observations of natural events such as forest fires and dust episodes. Satellite imagery and aerosol optical depth measurements give visual evidence of the movement of pollutants across boundaries (Figure A-12). This particular episode clearly demonstrates movement of air masses and the associated pollutants from Canada to a large geographic area within Canada and to the south into the United States.

A.5 SUMMARY

The United States and Canada share three principal air quality problems contributing to degradation of air quality, health, and visibility: fine particles ($PM_{2.5}$), tropospheric ozone, and acid deposition. Transport of key precursor emissions such as SO_2, NO_X, VOCs, and NH_3

Figure A-12 Satellite Imagery of the Quebec Forest Fire PM Episode in July 2002



Source: Canada–United States Transboundary PM Science Assessment, 2004.

can lead to the formation of acid deposition and ground-level ozone (smog).

A significant portion of the population in the eastern border regions of both Canada and the United States is exposed to levels of air pollutants that exceed air quality standards designed to protect human health. As well, acidic deposition remains at levels that cause concern for sensitive ecosystems. While there have been significant reductions of the emissions of these key pollutants, poor air quality, visibility problems, regional haze, and acid deposition continue to be recorded in the shared border region between Canada and the United States.

Observational evidence, in combination with emission information and air quality model applications, has been used by both Canada and the United States to determine the source regions that contribute to poor air quality in the transboundary region. These scientific results have led to the recognition of the value of a borderless approach to air quality management.

Further emission reductions have been identified as necessary to improve air quality and visibility and reduce acid deposition and regional haze in the shared cross-border region. An emissions cap and trading program can reduce the total loading of a pollutant into the atmosphere. Emissions cap and trading is most effective when pollutants are emitted by many sources and transported over a large geographic region. The data presented here support the conclusion that such a case exists along the U.S.-Canada border region.

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SECTION B

LEGAL BACKGROUND

In both Canada and the United States, different levels of government share jurisdiction over environmental affairs, and this is reflected in the environmental laws of each country. In Canada, both the federal and provincial levels of government play a role in the regulation of sulfur dioxide (SO_2) and nitrogen oxide (NO_X) emissions. In the United States, state governments are responsible for implementing much of the environmental legislation, but the federal government sets ambient air quality standards and overall emission limitations.

This section analyzes the legal framework relevant to a cross-border emissions cap and trading program. Since there are no national emission cap and trading programs in Canada to date, this section describes the legal authority whereby Canada could establish such a regime. For the United States, this section also describes the existing U.S. emission cap and trading programs and discusses some of the technical requirements of a cross-border trading program. The U.S. currently does not have any emission cap and trade programs that involve international emissions trading, nor is it clear the extent to which authority exists under the Clean Air Act to establish such a program. Legislative and/or regulatory action would likely be required to authorize a cross-border emissions cap and trading program for SO_2 and NO_X. Section B.1 describes the regulation of SO_2 and NO_X in the United States, while Section B.2 describes regulation in Canada.

B.1 UNITED STATES

In the United States, the federal U.S. Environmental Protection Agency (EPA) develops and enforces regulations that implement environmental laws enacted by Congress. EPA is responsible for researching and setting national standards for a variety of environmental programs and in many instances delegates to states and tribes the responsibility for issuing permits and for monitoring and enforcing compliance, while continuing to reserve the authority to enforce compliance itself where necessary. Where national standards are not met, EPA can issue sanctions and take steps to assist the states and tribes in reaching the desired levels of environmental quality. A state always has the option, unless barred by state law, to impose stricter standards than those required by the federal government in order to meet environmental goals.

B.1.1 The Clean Air Act

The Clean Air Act (CAA) gives EPA the authority to set permissible atmospheric concentrations for "criteria pollutants" for the entire country. To date, such limits have been set for particulate matter (PM), carbon monoxide (CO), nitrogen dioxide (NO_2), sulphur dioxide (SO_2), ozone (O_3), and lead. EPA sets these limits, referred to as National Ambient Air Quality Standards (NAAQS), taking into account human health and the prevention of environmental and property damage. Individual states can set stricter pollution standards, but cannot have weaker standards. In addition, other environmental regulations cannot supersede the NAAQS. While there is flexibility in the method and timing of meeting emission reduction requirements of Title IV of the Clean Air Amendments of 1990 (CAAA), as described below, the NAAQS still limit the total permissible concentrations of the criteria pollutants in a given area. Titles I (NAAQS) and IV (Acid Rain Program) are complementary.

Individual states have responsibility for achievement of the NAAQS. Each state must prepare a State Implementation Plan (SIP) that outlines planned measures to meet the air quality standards. For the purpose of assessing air quality, each state is divided into smaller air quality areas. Each area is designated as being in attainment or nonattainment for each of the criteria pollutants. SIPs focus mainly on the measures and schedules designed to bring nonattainment areas into attainment. EPA reviews and approves each SIP and can take over the implementation of the NAAQS in a state if the SIP is not adequate.

The CAA also identifies 189 hazardous air pollutants, which are chemicals known to present a threat of serious health or environmental hazards. EPA can add to this list as necessary and must issue regulations to reduce the emissions of these pollutants from different types of stationary sources. Sources are required to use the Maximum Achievable Control Technology (MACT) to reduce emissions of hazardous air pollutants.

The CAA permitting system, outlined in Title V, is the primary mechanism for regulating many types of stationary sources. Source permits, usually issued by states, specify which pollutants are currently emitted by the source, the maximum amount that may be emitted, and the steps the owner or operator must take to monitor and reduce emissions. All of the information relevant to the CAA is contained in a single permit, and EPA can issue fines for violation of the terms of the permit.

The CAA also includes provisions for controlling pollution that travels across areas and states. For example, states can form interstate commissions to develop regional strategies for controlling air pollution, and EPA can issue regulations designed to limit interstate transport of emissions.

B.1.2 Title IV – Acid Rain

Acid rain receives special attention in the CAAA because the long-range transport of acidic compounds places the problem beyond the control of any one state or region. The purpose of Title IV is to reduce environmental damage resulting from acid deposition by lowering emissions of SO_2 and NO_X from the combustion of fossil fuels, primarily by power plants. Title IV sets a national goal of reducing total annual SO_2 emissions by 10 million tons[1] below 1980 levels (primarily through a cap and trade program) and a goal of reducing annual NO_X emissions by approximately 2 million tons.

B.1.2.1 SO_2

SO_2 emissions are reduced to the capped level through an emissions cap and trading program.

Coverage

Title IV mandates a two-phase approach to achieving SO_2 emission reductions at fossil fuel-fired electricity generating plants. Phase I began in 1995 and affected 263 units at 110 mostly coal-burning electric utility plants located in 21 eastern and midwestern states.[2] Under Phase II, which began in 2000, Title IV broadened coverage to virtually all existing fossil fuel-fired electricity generating units serving generators with a nameplate capacity greater than 25 megawatts (MW), as well as virtually all new units, regardless of size. In addition to the large coal-fired units, Phase II requires that smaller, cleaner plants fired by coal, oil, and gas—encompassing over 3,000 units in all—hold allowances for their SO_2 emissions.

Allowances

The overall cap for SO_2 emissions is divided into allowances, each of which currently authorizes a unit to emit one ton of SO_2 during or after a specified year. Existing affected utility units—but not new units—are allocated allowances based on the product of their historic fuel consumption and a specific emissions rate. At the end of each calendar year, the owners or operators of each unit must surrender one allowance for each ton of SO_2 emitted from that unit during the year. Allowances may be bought, sold, or banked, but once they are used for compliance, they cannot be used again. Anyone may acquire allowances and participate in the trading system. Regardless of the number of allowances a source holds, it may not emit at levels that would violate any other requirements of the CAA.

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[1] One ton = 2,000 pounds ≈ 0.9072 tonne.

[2] An additional 182 units joined Phase I of the program as substitution or compensating units, bringing the total of Phase I affected units to 445.

Emissions Monitoring

In addition to allowance-holding requirements, each unit must continuously measure and record its emissions of SO_2, NO_X, and carbon dioxide. This monitoring requirement ensures the credible accounting of emissions that is necessary to guarantee the integrity of the market-based allowance system and to verify the achievement of the emission reduction goals. Rigorous monitoring standards instill confidence in allowance transactions by certifying the underlying emission values of the commodity (i.e., allowances) being traded and ensure that the government can track progress toward the emission reduction targets.

In most cases, a unit must have a continuous emission monitoring system (CEMS) installed to be in compliance with Title IV. EPA has issued detailed regulations for CEMS (40 CFR Part 75), including initial equipment certification procedures, periodic quality assurance and quality control procedures, record-keeping and reporting requirements, and procedures for filling in missing data periods. All CEMS must be in continuous operation and must be able to sample, analyze, and record data at least every 15 minutes. In some instances, Part 75 allows oil- and gas-fired units to use less rigorous "excepted" monitoring methods (e.g., fuel flow metering and fuel sampling) in lieu of CEMS. Affected sources may also petition EPA to use alternate monitoring systems; to be approved, an alternative system must demonstrate accuracy and reliability comparable to a CEMS.

If CEMS data, data from an excepted method, or data from an alternative monitoring system approved by EPA are not available for any affected unit during any period, the unit is considered to be operating in an uncontrolled manner for the period for which the data were not available. EPA has prescribed formulas, some of which are very conservative, to calculate emissions for periods of missing data, and the owner or operator is liable for excess emission fees and must still ensure that it holds sufficient allowances to offset the higher calculated emissions. There is also a fine for noncompliance with monitoring provisions. (See Section D for greater detail on monitoring and reporting.)

Permits

The owner or operator of each source is required to file a permit application and a compliance plan under Title V of the CAA. Acid rain permits require that the owner or operator hold for each affected unit a sufficient number of allowances to cover the unit's SO_2 emissions in each year, comply with the applicable NO_X limit, and monitor and report emissions. Permits are subject to public comment before approval. Other than these basic requirements, the Title V permitting system does not prescribe any specific actions that must be undertaken by owners and operators. Sources have broad flexibility in how they meet the allowance-holding provisions of Title IV, e.g., by reducing emissions or by buying allowances, so long as they hold sufficient allowances at the end of the year to cover their annual emissions for that year.

Opt-ins

The Acid Rain Opt-in Program provides sources not required to participate in the Acid Rain Program with the opportunity to enter the program on a voluntary basis, comply with Part 75 for emissions monitoring, and receive their own SO_2 allowances. To date, however, only a small number of units have opted in to the program.

B.1.2.2 NO_X

Title IV of the CAAA also set a goal of reducing NO_X emissions by approximately 2 million tons. The NO_X program provides some flexibility for sources to choose the method to achieve emission reductions, but does not "cap" NO_X emissions as the SO_2 program does, nor does it utilize an allowance trading system. Instead, affected sources must meet a NO_X emissions rate, expressed in pounds of NO_X per million British thermal units (mmBtu)[3] of heat input. An affected source can meet the emissions rate for an individual boiler or by averaging its emission rates with those of one or more other boilers with the same owner or operator.

Phase I of the NO_X program began on January 1, 1996, and applied to two types of boilers that were already targeted for Phase I SO_2 reductions: larger dry-bottom wall-fired boilers and tangentially-fired boilers. Approximately 170 boilers needed to comply with the NO_X emissions rates during Phase I. Phase II of the NO_X program, which began in 2000, set lower emission limits for remaining wall- and tangentially-fired boilers and established initial NO_X emission limitations for boilers applying cell-burner technology, cyclone boilers, wet-bottom boilers, and other types of coal-fired boilers.

B.1.3 Ozone Transport Commission NO_X Budget Program

In 1994, a number of eastern states formed the Ozone Transport Commission (OTC) to develop a regional approach to reducing NO_X emissions,[4] as prescribed under the Clean Air Act Amendments of 1990. Most of the states in the OTC were facing difficulties meeting the NAAQS for ozone through individual state measures because of regional transport. Under the OTC, these states agreed to develop and adopt a regulatory cap and trading program to reduce NO_X emissions from electricity generators and large industrial boilers starting in 1999. EPA provided assistance to the states by helping them develop a "model rule," which states could adopt and which identified elements of the trading system that needed to be consistent across states. These elements included source applicability (sector coverage), control period, allowance trading and banking requirements, emissions monitoring, record-keeping for emissions and allowances, and electronic reporting requirements.

B.1.3.1 Common Elements

Applicability

The program affected all fossil fuel-fired boilers or indirect heat exchangers with a maximum rated heat input capacity of 250 mmBtu/hour or greater and all electricity generating facilities with a rated output of 15 MW or greater. States had the option of requiring additional sources—both below the threshold and in other sectors—to participate in the trading program if they could monitor emissions properly.

NO_X Budgets

The OTC NO_X regional budget was established in 1995 based on discussions among states, industry, EPA, and environmental groups. The group applied the overall emissions reduction target to 1990 baseline emissions from affected sources and then divided the resulting total cap among participating states. Each state was then responsible for allocating allowances to specific sources, but the emission caps, or state trading budgets, could not be changed.

Control Period

The control period in which units had to limit their emissions lasted from May through September, corresponding to the annual peak ozone season. Beginning in 1999, the sum of NO_X emissions from affected sources during the May through September control period could not exceed the equivalent number of allowances allocated in the region, and each source had to hold an amount of allowances at least equal to its NO_X emissions. The affected sources were allowed to buy, sell, or trade allowances to meet their needs. In 2003, the OTC states adopted lower caps under the NO_X SIP call, which superseded the OTC trading program (see Section B.1.4 below). Compliance is determined annually after the end of the control period by ensuring that each affected source has sufficient allowances to match its emissions. Sources can bank allowances forward to subsequent years, but cannot emit at levels that would violate other CAA or state requirements.

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[3] One Btu = 1.06 kilojoules.

[4] Maine, New Hampshire, Vermont, Massachusetts, Connecticut, Rhode Island, New York, New Jersey, Pennsylvania, Maryland, Delaware, northern Virginia, and the District of Columbia.

Monitoring, Allowance Tracking, and Reporting

As with SO_2 under the Title IV Acid Rain Program, affected sources under the OTC were required to monitor emissions, primarily with CEMS. Low-emitting sources such as gas-fired power plants could use other estimation methods, provided they offered a similar level of accuracy. The OTC states requested that EPA develop the NO_X allowance and emissions tracking systems (see Section F) on the basis of the existing federal SO_2 systems. They also asked EPA to administer the annual reconciliation and compliance procedures. States retained the responsibility for allocations, auditing of source monitoring requirements, and enforcement of compliance.

B.1.3.2 Areas of Flexibility

Under the model rule, states were responsible for enacting state-level regulations to implement the OTC program, and they were charged with allocating allowances to affected sources in their jurisdiction. The OTC decided that discretion in allocation methodologies would not interfere with the operation of the trading system, and therefore states could choose different approaches to allocation. States were also responsible for determining baselines for sources that opt in to the program and had the option to set aside allowances for early reductions prior to the start of the program, for renewable and energy efficiency projects, and for new entrants.

B.1.4 The NO_X SIP Call

In 1998, EPA announced that a large number of eastern states would be required to submit new NO_X SIPs.[5] EPA concluded that, because of the long-range transport of ozone, these states would continue to interfere with other states' ability to achieve attainment with ozone air quality standards without further reductions of regional emissions. The SIP call established state budgets for total NO_X emissions during the ozone season from May 1 to September 30 each year. Each state had the freedom to enact specific measures to meet the emission limitations for various sectors outlined in the SIP call, but EPA developed a model rule for states that preferred an emissions cap and trading approach for stationary sources to achieve required reductions. Under the model rule, EPA administers an ozone season NO_X cap and trading program for states that choose to participate in the program. The similarity of this model rule to the OTC NO_X Budget Program model rule allowed states participating in the OTC to transition smoothly into the NO_X SIP call program, known as the NO_X Budget Trading Program.

B.1.4.1 The Model Rule - Common Elements

The model rule set forth mandatory elements of the NO_X Budget Trading Program. States could choose not to adopt the EPA-administered trading program as a whole, but if they decided to participate in that trading program, they had to adopt the entire model rule with only a few types of changes being allowed. The mandatory elements ensured consistency across states in development of a regional emissions cap and trade program. Such consistency is essential to guarantee a cost-effective emissions market, a transparent monitoring and compliance regime, and the value and validity of an allowance. With regard to a few elements, such as allowance distribution and set-asides, states had some discretion to modify the rule.

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[5] SIP call states included Alabama, Connecticut, the District of Columbia, Delaware, Illinois, Indiana, Kentucky, Massachusetts, Maryland, Michigan, North Carolina, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, West Virginia, Wisconsin, Georgia, and Missouri. Following litigation in 2000, Wisconsin was dropped from the program and Georgia and Missouri were given compliance dates of 2007.

Applicability

To adopt the model rule, states had to include all fossil fuel-fired electricity generators with a rated capacity of greater than 25 MW and all industrial boilers and turbines with a rated thermal input of greater than 250 mmBtu/hour. The OTC states that transferred into the NO_X SIP call (all except New Hampshire) could maintain their applicability threshold of electricity generators with equal to or greater than 15 MW capacity.

Monitoring

As with the SO_2 trading program, all affected sources are required to monitor emissions using CEMS or an alternative methodology of equivalent rigor. EPA updated Part 75 of the Title IV regulations to include provisions for monitoring and certification, data review, quality assurance tests, and quarterly reporting with regard to NO_X mass emissions from both electricity generating units and industrial sources under an emissions cap and trade program. EPA is responsible for establishing and maintaining the centralized emissions data tracking system.

Timing of Allocation

EPA allocates NO_X allowances to sources on a schedule determined by each individual state. Generally, allocation occurs a number of years before the compliance period to facilitate market liquidity and provide owners and operators with the certainty needed for long-term emission reduction planning. The annual compliance period for the NO_X SIP call is the five-month ozone season, from May through September. The allowance reconciliation process follows a two-month period in which sources can make additional allowance transfers.

Banking

An allowance is defined as an authorization to emit one ton of NO_X during a particular season. Sources cannot use an allowance before its year of allocation or "vintage," but unused allowances can be banked for use in future years. The "Progressive Flow Control" provision changes the status of banked allowances if the total bank exceeds 10 percent of the regional budget. Under these conditions, a source can use only a portion of its banked allowances for compliance without penalty. The remaining banked allowances must be surrendered on a two-to-one basis (two banked allowances to cover one ton of emissions). This feature is designed to discourage large-scale fluctuations in emissions—and in attainment status—in a particular ozone season that could raise concerns regarding seasonal air quality.

Compliance

As with the SO_2 program, all sources must hold sufficient allowances to cover emissions, in this case during the summer ozone season. EPA performs the annual reconciliation process to assess compliance and implements an automatic offset of three allowances for each ton of excess emissions. States take the lead with additional enforcement actions, including fines, and the affected sources are still covered by all other relevant CAA provisions.

B.1.4.2 State Flexibility

Allocation Method

States receive total NO_X budgets on the basis of emission baselines from affected sources, but they have discretion to determine the allocation methodology. States can allocate to sources based on historical emissions, through periodic updating, or through any other combination of methodologies, provided they do not allocate more than the allotted state budget. The allocation methodologies are outlined in each state's SIP adopting the NO_X Budget Trading Program model rule.

Set-asides

States may also set aside a portion of the NO_X budget to provide incentives for early reductions, new renewable energy generation, and demand-side energy efficiency measures.

Additional Sources

Provided they can meet the same stringent emission monitoring and reporting standards, states may elect to require participation in the trading program of electricity generators or industrial boiler units that fall below the size thresholds outlined in the model rule, as well as other types of sources. In addition, they may elect to adopt procedures under which individual sources not otherwise subject to the trading program opt in (voluntary entry), assuming they meet certain requirements, including the same stringent emissions monitoring and reporting.

Additional Regulatory Measures

The model rule does not preempt any existing state-level regulations on NO_X emissions and air quality. For example, states must still meet the NAAQS for ozone. Furthermore, an affected source cannot emit at levels above permitted levels, regardless of how many allowances it holds.

B.1.5 Proposed U.S. Multipollutant Legislation and Final Regulations

B.1.5.1 Legislation: Proposed Clear Skies[6]

Though the experience with allowance trading has been successful, the United States is committed to further reductions in NO_X and SO_2 emissions necessary to attain the NAAQS and to reduce acid rain, reduce regional haze, and address other environmental concerns. The proposed Clear Skies Act (2003) would create a national multipollutant trading program for electricity generators, to be centrally managed by EPA, which would build upon the existing SO_2 program, NO_X SIP call, and existing CAA regulatory authority for mercury emissions. As with all proposed legislation in the United States, the proposed Clear Skies Act (2003) has to be passed by Congress in order to become law. An alternative regulatory approach under the existing CAA, the Clean Air Interstate Rule (CAIR), which requires reductions for NO_X beginning in 2009 and SO_2 in 2010, was finalized in March 2005; it is described in Section B.1.5.2.

B.1.5.2 Regulation: The Clean Air Interstate Rule

As part of its commitment to ensure further reductions in NO_X and SO_2, EPA promulgated a final regulation called the Clean Air Interstate Rule (CAIR).[7] CAIR is a regulatory alternative to enacting new legislation. Under this regulatory initiative, EPA is making use of its existing authority under the CAA to require further reductions in emissions if current regulations are insufficient to meet the NAAQS. As with the NO_X SIP call, states have the flexibility to decide which sources to control to meet the state emissions budget, and EPA has developed an optional cap and trade program similar to the current Acid Rain Program.

The geographic coverage of the rule is confined to states that have been shown to contribute significantly to ozone and particulate matter nonattainment areas in other states. Most states in the east are controlled for both SO_2 and NO_X annual emissions, and a slightly larger number of states are controlled for NO_X emissions during the ozone season. Western states are not covered under CAIR.

The caps and timing occur in two phases. For SO_2, the Phase I cap of 3.6 million tons begins in 2010 and declines to 2.5 million tons by the beginning of Phase II in 2015. The NO_X program begins a year earlier, in 2009, with the

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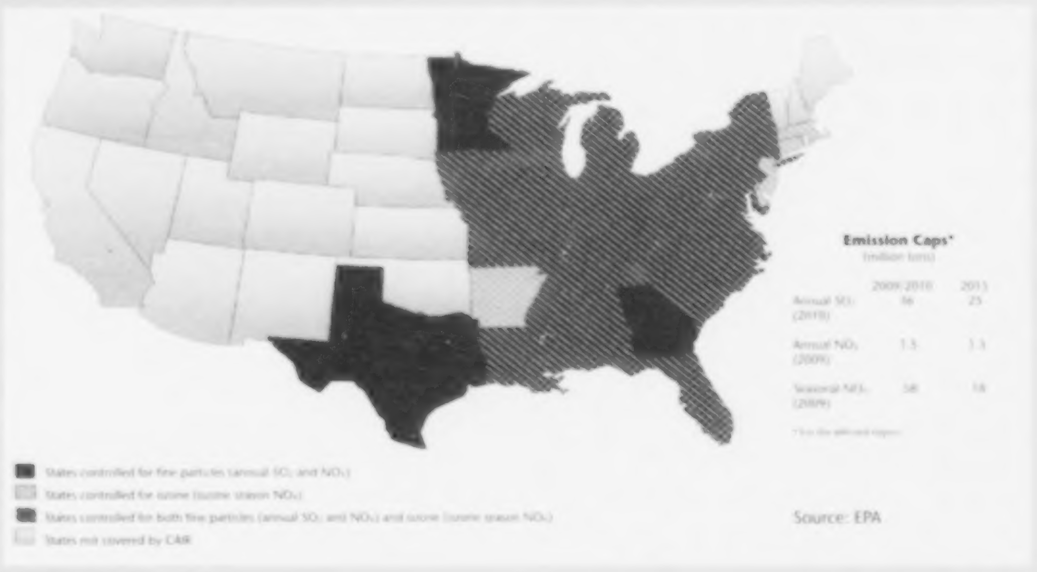
[6] See **http://www.epa.gov/clearskies/** for more information.

[7] See **http://www.epa.gov/cleanairinterstaterule/** for more information.

Figure B-1 CAIR: Affected Region and Emission Caps


Emission Caps*
(million tons)
2009/2010
2015
Annual SO_2 (2010)
3.6
2.5
Annual NO_X (2009)
1.5
1.3
Seasonal NO_X (2009)
.58
.58
* For the affected region
States controlled for fine particles (annual SO_2 and NO_X)
States controlled for ozone (ozone season NO_X)
States controlled for both fine particles (annual SO_2 and NO_X) and ozone (ozone season NO_X)
States not covered by CAIR

Source: EPA

Phase I cap set at 1.5 million tons and the Phase II cap set at 1.3 million tons in 2015 (Figure B-1).

Overview of the Trading Programs

CAIR includes three model rules that states may adopt in order to achieve required SO_2 and NO_X emission reductions, through an emissions cap and trading approach. The model rule for the SO_2 trading program is designed to work with the existing Title IV program. Title IV allowances continue to be used in the new SO_2 trading program. CAIR SO_2 emission reductions in the trading program are achieved through retirement ratios of Title IV allowances, not through a budget for new allowances. Sources turn in Title IV allowances for 2010 or later at a ratio greater than one-to-one to ensure reductions beyond Title IV. Sources may use pre-2010 allowances at a one-to-one ratio. This approach preserves the viability of the Title IV program and maintains the confidence in the market for Title IV allowances.

There are two model rules for NO_X: one for an annual NO_X trading program and one for an ozone season NO_X trading program. Each program sets a budget for CAIR NO_X allowances, which represents the number of allowances that a state receives and has discretion to allocate. The annual NO_X trading program provides sources with additional allowances from a fixed compliance supplement pool, e.g., for early reductions.

The ozone season NO_X trading program allows sources to use banked allowances from the NO_X SIP call. NO_X SIP call sources that are not part of CAIR (e.g., industrial boilers) may be brought into the ozone season NO_X trading program.

Emissions Monitoring

Sources are required to comply with 40 CFR Part 75 emission monitoring provisions.

Permits

CAIR permits are required for sources required to have a Title V permit and opt-in sources. Permits are issued by the state or local permitting authority.

Opt-ins

States can choose to allow sources to opt in to the CAIR trading programs. Opt-ins are limited to boilers, turbines, or other fossil fuel-fired combustion devices that vent all emissions through a stack and are able to meet Part 75 emission monitoring and reporting requirements. There are two mechanisms that the states can use to allow an opt-in, and they may choose one or both. The first effectively requires—through reduced allowance allocations—a 30 percent reduction in emissions, and the second has special provisions and requirements for sources that repower with qualifying technologies.

Banking

The CAIR trading programs allow unrestricted banking of allowances. Additionally, banked allowances from the NO_X SIP call can be used in the CAIR ozone season NO_X trading program, and banked Title IV allowances can be used in the CAIR SO_2 trading program. There is no flow control under CAIR.

Compliance

The compliance, or "true-up," process in the CAIR trading programs is somewhat different for SO_2 than for NO_X. For both SO_2 and NO_X, each source must hold in its compliance account a tonnage equivalent of allowances at least equal to the tonnage of emissions during the control period (i.e., a calendar year for SO_2 and a calendar year or an ozone season for NO_X). However, in the CAIR SO_2 trading program, Title IV allowances are used for compliance as follows: each pre-2010 vintage allowance authorizes one ton of SO_2 emissions; each 2010-2014 vintage allowance authorizes 0.50 ton of SO_2 emissions; and each 2015 and later vintage allowance authorizes 0.35 ton of SO_2 emissions. In the CAIR NOx trading programs, each NO_X allowance authorizes one ton of NO_X emissions, but CAIR ozone season NO_X allowances may not be used in the CAIR annual NO_X trading program and vice versa. Additionally, the amount of NO_X allowances allocated (i.e., the cap) is reduced in 2015 and beyond, in both the annual and ozone season NO_X trading programs.

Flexibility

CAIR requires affected states to make reductions in SO_2 and NO_X and offers EPA-administered trading programs, set forth in model trading rules, as one way to achieve the required reductions. However, states can choose the method for achieving the reductions and do not have to use the EPA-administered trading programs. States that use these trading programs must adopt the relevant model trading rule, with only a few changes allowed. In particular, states have the flexibility to allocate NO_X allowances as they choose in these trading programs. EPA offers a possible allocation methodology, but does not require its use. The CAIR SO_2 trading program relies on acid rain allowances that are already allocated, so states do not have this flexibility for SO_2. As explained in the opt-in section, states do not have to include the opt-in provisions in their trading rules.

B.2 CANADA

B.2.1 Introduction

Environmental jurisdiction in Canada is shared between the federal and provincial governments. The "environment" is not granted as an express head of power in the Constitution Act, 1867 and 1982. Rather, a division of powers set forth in sections 91 and 92 of the Constitution Act grants both federal and provincial governments authority over the environment under diverse powers, both legislative and proprietary. For instance, provinces have traditionally handled electricity generation. Because there is no national emissions cap and trading program in Canada to date, this section sets forth a view of how Canada could establish, legally, a cross-border emissions cap and trading regime with the United States.

The Government of Canada is responsible for assuming Canada's international commitments, such as the Canada-U.S. Air Quality Agreement. As described below, the Canadian Environmental Protection Act, 1999 (the Act or CEPA) enables the Minister of the Environment to regulate toxic air emissions, including domestic emissions which may lead to air pollution in other countries. The Act empowers the federal government to establish a system of tradable units when controlling either domestic or international air pollution. It also allows the Minister of the Environment to enter into agreements with provincial governments regarding the execution and administration of some of these responsibilities.

B.2.2 Canadian Environmental Protection Act, 1999

B.2.2.1 Toxics Provisions

CEPA, Part 5, provides the federal government with authority to regulate toxic substances. Both SO_2 and NO_X have been included in the Act's List of Toxic Substances, found in Schedule 1 (ss. 62-64). At present, Environment Canada places prohibitions on the production, emission, import, and export of many toxic substances, including SO_2 and NO_X, through regulations issued under the Act.[8]

Sections 93 and 330 of CEPA provide the legal authority for Environment Canada to make regulations with respect to the quantity or concentration of a toxic substance that may be released into the environment, the manner and conditions under which it may be released, the monitoring, reporting, and testing of such releases, and other similar elements.

Section 326 of the Act, as shown below, allows the creation of a system of tradable units when regulating toxics:

> *326. The Governor in Council may, in the exercise of a regulation-making power under section 93, 118, 140, 167, 177 or 209, make regulations respecting systems relating to tradeable units, including regulations providing for, or imposing requirements respecting,*
>
> *(a) the substance, product containing a substance or quantity or concentration of the substance that is released or activity in relation to which the system is established;*
>
> *(b) the methods and procedures for conducting sampling, analyses, tests, measurements or monitoring under the system;*
>
> *(c) the description and nature of a tradeable unit, including allowances, credits or coupons;*
>
> *(d) the baselines to be used for comparison or control purposes in relation to the system and the maximum limits applicable to the system and the manner of determining those baselines and maximum limits;*
>
> *(e) the conditions related to the creation, distribution, exchange, sale, use, variation or cancellation of a tradeable unit;*
>
> *(f) the creation, operation and management of a public registry related to the system;*
>
> *(g) the conditions for the use of and participation in the system, including environmental or temporal limits;*
>
> *(h) reports and forms related to the system; and*
>
> *(i) the maintenance of books and records for the administration of any regulation made under this section.*

Among other elements, this system may determine the nature of the tradable unit, conditions required for its use, maximum limits applicable to the system, and the creation of a reporting scheme and public registry related thereto. When creating such an emissions trading regime based on the toxics provisions of the Act, the Minister of the Environment is required to consult with the provinces through the National Advisory Committee, established under section 6 of CEPA.

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[8] For example, persons having charge of listed substances, including nitrogen dioxide (NO_2) and SO_2, must develop emergency preparedness plans under the Environmental Emergency Regulations, SOR/2003-307; airborne release of asbestos fibers from a mine or mill is controlled under the Asbestos Mines and Mills Release Regulations, SOR/90-341; the production, import, and export of certain ozone-depleting substances are controlled under the Ozone-Depleting Substances Regulations, 1998, SOR/99-7; and the airborne release of maximum concentrations of lead particulate matter from smelters is regulated by the Secondary Lead Smelter Release Regulations, SOR/91-155.

B.2.2.2 International Provisions

Sections 166-167 of the Act give the federal Minister the authority to prevent international air pollution and to make regulations to that effect. Under these provisions, the Minister is first required to consult with the provincial government responsible for the source of the pollution to determine whether it can prevent the contamination under its laws and give the province the opportunity to do so. Only if the province is unable or unwilling can the federal government then act.

In the event that the province cannot or does not control the air pollution, then the federal Minister can either request a pollution prevention plan from the offending source or develop regulations to prevent or control the problem. If the Minister proceeds by way of regulation, then section 326, as described above, provides that when regulating international air pollution under section 167, the Minister of the Environment may develop a system of tradable units.

B.2.2.3 Equivalency and Administrative Agreements

In the United States, the NO_x SIP call program uses a model federal rule for states that prefer an emissions cap and trade approach for stationary sources to achieve required reductions. This model rule approach may provide a useful example for Canada to understand in the context of establishing a cross-border emissions cap and trading program where federal and provincial governments each have a significant part of the responsibility.

The Department of the Environment Act provides that the Minister of the Environment may enter into agreements with a province or provincial agency to carry out programs for which the federal Minister is responsible. The preamble to CEPA expressly notes that all governments in Canada have authority that enables them to protect the environment and that environmental protection can be better served through cooperative resolution.

CEPA (s. 10) allows the creation of equivalency agreements between the federal and provincial governments. Under these agreements, Canada suspends the application of a federal regulation when the Minister of the Environment is satisfied that a provincial law is equivalent, with respect to both provisions governing the subject matter at hand and provisions allowing for the investigation of offenses, as found in sections 17 to 20 of the federal Act.[9] CEPA expressly contemplates equivalency agreements for regulations under the toxics provisions of the Act (s. 93), as well as for regulations under the international air pollution provisions (s. 167).

By way of example, an equivalency agreement was created between Canada and Alberta,[10] declaring that four federal toxics regulations do not apply in the province.[11] The agreement specifically sets forth that the Alberta Environmental Protection and Enhancement Act establishes testing and approval standards, citizens' requests for investigations, penalties, and enforcement mechanisms that are equivalent to provisions under CEPA. Alberta also undertakes prospectively, when amending any of the implicated legislation, not to create provisions that are any less stringent than the relevant CEPA regulations.

In order for Canada to proceed with an emissions cap and trading program under the equivalency provisions of section 10, each province would be required to have legal provisions in force that are equivalent to a federal regulation made under CEPA as well as provisions allowing for the investigation of offenses, as found in sections 17 to 20 of the federal Act.

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[9] Section 17 of CEPA allows any individual resident in Canada and over 18 years of age to request the Minister of the Environment to investigate an alleged offense. Section 18 requires the Minister to investigate; section 19 requires the Minister to report on the investigation; and section 20 allows the Minister to transfer evidence of any suspected offense under the Act to the Attorney General.

[10] An Agreement on the Equivalency of Federal and Alberta Regulations for the Control of Toxic Substances in Alberta, 1994; Alberta Equivalency Order SOR/94-752.

[11] Pulp and Paper Mill Effluent Chlorinated Dioxins and Furans Regulations, SOR/92-267; Pulp and Paper Mill Defoamer and Wood Chip Regulations, SOR/92-268; Secondary Lead Smelter Release Regulations, SOR/91-155; and Vinyl Chloride Release Regulations, 1992, SOR/92-631.

The Act also provides for administrative agreements (s. 9) whereby Environment Canada may enter into accords with provincial governments with respect to the administration of the Act. Unlike the equivalency provisions of section 10, an administrative agreement under CEPA does not require that a province have legislation equivalent to the federal regulations in question, nor does the agreement suspend application of the federal law. Rather, it enables a provincial government to administer the federal program that is the subject of the agreement.

These cooperative mechanisms are typically upheld by the courts as a way of minimizing either the inefficiencies or the controversy caused by overlapping environmental jurisdiction.

B.2.3 Local Air Quality Requirements in Provinces

While emissions cap and trading programs can reduce emissions from sources participating, they do not replace provincial (or municipal) industrial facility-specific requirements that provincial governments put in place to ensure local air quality.

All Canadian provinces have ambient air quality criteria for SO_2 and NO_2. These criteria are used to monitor air quality and may be relied upon to set emission limits for new sources. Provincial permitting, however, is often based upon ambient air quality standards instead of on maximum emission limits from a given source. The term limits on operating permits also vary from province to province. Provincial emission permits typically include monitoring and reporting requirements as well as compliance and enforcement measures.

B.2.3.1 Ontario

Industrial facilities above a minimum threshold that discharge airborne contaminants are required to obtain a certificate of approval under the Ontario Environmental Protection Act. The approvals process specifies maximum emission concentrations. Regulation 346 sets point of impingement standards for air quality, designed to protect public health from local air quality effects. Approvals are issued for an indefinite duration, though significant modifications to a facility that result in additional emissions or a change in the nature of the emissions will require a new approval. Facilities are required to monitor and report annual and smog season total emissions in conformity with Regulation 127/01. This latter regulation covers the quarterly reporting of SO_2 and NO_X.

Ontario has an SO_2 and NO_X emissions reduction and trading program under Regulation 397/01, in force since December 31, 2001, issued under the provincial Environmental Protection Act. The regulation allocates emission allowances to designated emitters and establishes a trading and credit regime. Until recently, only Ontario Power Generation was covered by this regulation at six coal- or oil-fired electricity generating facilities. In 2004, the program was expanded to cover all generators that have over a 25 MW capacity, that sell more than 20,000 megawatt hours (MWh) annually, or that emit more than a threshold amount of nitric oxide (NO) and SO_2. The Ontario Ministry of the Environment will lower the number of allowances currently allotted to Ontario Power Generation and distribute new allowances to the incoming emitters. A detailed description of the program can be found at **http://www.ene.gov.on.ca**.

B.2.3.2 Quebec

The Loi sur la qualité de l'environnement (LQE) governs activities within the province that have adverse environmental impacts. The LQE defines activities having such adverse impacts as those involving construction, modification, or increase in production that will adversely affect the environment by emitting waste or airborne contaminants. Prior to engaging in such activities, a proponent must obtain a certificate of approval. Some exemptions exist for facilities operating below specified thresholds.

A regulation under the LQE, the Règlement sur la qualité de l'atmosphère (Atmospheric Quality Regulations, Q-2, r.20), provides maximum permissible ambient air concentrations for both SO_2 and NO_2, as well as maximum permissible stack emission levels of SO_2 and NO_2 for fossil fuel combustion facilities. In general, these standards are point of impingement and opacity standards.

B.2.3.3 British Columbia

The Ministry of Land, Water and Air Protection administers the new Environmental Management Act, which permits industrial activities discharging contaminants into the environment. Provincial air quality objectives and standards govern the levels of discharge that are deemed permissible. Air quality is monitored through a variety of opacity and stack emission tests, set forth in the British Columbia Field Sampling Manual.

The oil and gas industry is covered by sector-specific statutory emission limits and is governed by the Oil and Gas Waste Regulations.[12]

Within the Greater Vancouver region, the permitting process has been delegated to the Greater Vancouver Regional District. The municipal government has created bylaws to designate those activities subject to or exempt from the permitting process.[13] The Vancouver permitting process establishes limits on the quantity and frequency of air emissions, requires monitoring and reporting of six common contaminants (CO, O_3, NO_2, SO_2, PM_{10}, and $PM_{2.5}$),[14] and sets fees, charged as part of the permitting process, as an incentive to reduce emissions.

B.2.3.4 Alberta

Emission controls, monitoring, and reporting requirements in Alberta are governed by the Approvals and Registrations Procedure Regulation under the Alberta Environmental Protection and Enhancement Act. Activities requiring approval are categorized into five different groups, designated in the Activities Designation Regulation. Activities producing air emissions are listed in Division 2 of the regulation. The approvals process, which covers major industrial point sources and the electric power generation sector, represents roughly 80 percent of total provincial NO_X emissions and 60 percent of total provincial SO_2 emissions.[15] In June 2001, Alberta created minimum emission standards for new coal-fired power plants.[16]

Alberta has provincial Ambient Air Quality Guidelines for both NO_2 and SO_2 and follows the Canada-wide Standards for ground-level ozone. Consistent with the federal monitoring guidelines, the province monitors ambient air quality, and the data are then collected by the Clean Air Strategic Alliance. The province has recently undertaken a significant feasibility study, exploring the potential for an air emissions trading program in Alberta.

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[12] The Greater Vancouver Regional District (GVRD) also has its own municipal permitting requirements for the Vancouver district. Although it follows the same emission standards as the province, the GVRD aims to limit the number of facilities operating within its boundaries, thereby lowering overall emissions for this populated area.

[13] Air Quality Management Bylaw, No. 937, 1999.

[14] The GVRD has adopted Environment Canada's Monitoring Protocol, EPS 1/PG/7.

[15] Alberta Environment Emission Trading Project, Major Feasibility Study, Preliminary Analysis and Discussion Document, Appendix C, March 2003, prepared by Cheminfo Services Inc. for Alberta Environment, pp. 63-64.

[16] Alberta Emission Standards for New or Expanded Coal-Fired Plants.

B.2.3.5 Saskatchewan

The Saskatchewan Clean Air Act requires operators of industrial sources, incinerators, or fuel-burning equipment to hold a provincial permit, with the exception of the oil and gas industry, which is regulated by the Oil and Gas Conservation Act, and the mining industry, which is governed by the Environmental Management and Protection Act. The permitting process includes compliance with the provincial Clean Air Regulations, which establish ambient air quality standards. Air quality is measured through a variety of stack sampling, point of impingement samples, and modeling. Modifications made to an industrial source that change its emissions require an application for a new permit.

B.2.3.6 Manitoba

The Manitoba Environment Act and its regulations govern the permitting of facilities that produce air emissions. The approvals process is set forth in the Act and the Licensing Procedures Regulation, while the classes of industrial facilities that are subject to the Act are contained in the Classes of Development Regulation. As with many other provinces, the oil and gas sector is separately governed by the Minister of Industry, Trade and Mines under the Oil and Gas Act.

Permissible air emissions are set by the provincial Ambient Air Quality Criteria and are measured through modeling and point of impingement analysis. A schedule lists maximum permissible time-based pollutant concentrations within the province. Each contaminant is classified as either an objective or a guideline, depending upon several factors, the objective classification being more stringent. Maximum concentrations of NO_2 and SO_2 are both listed as objectives.

B.2.3.7 New Brunswick

Provincial approval of operations that discharge contaminants is administered under the Clean Environment Act and the Clean Air Act and its regulations. Air quality objectives for SO_2 and NO_2 are set under the Clean Air Act.[17] The type of approval required is determined by the volume of emissions released by a facility, with Class 1 sources having the greatest emissions. The electricity generation sector generally falls within Class 1. These approvals contain a formal, public participation component, including a provision allowing anyone affected by an approval to appeal the decision to the Minister of the Environment. Major modifications to an existing facility require a new permit.

B.2.3.8 Nova Scotia

The Nova Scotia Environment Act and its regulations set forth the requirements for approvals of facilities that produce air emissions. The approvals process is administered under the Approvals Procedures Regulations, and the classes of industrial facilities that require approval are listed in the Activities Designation Regulations. The Air Quality Regulations set maximum permissible concentrations for certain contaminants, including SO_2 and NO_2. Facilities are required to show how they will comply with emission limits, and monitoring and reporting of performance may be required here. Major modifications require an application for approval.

B.2.3.9 Newfoundland and Labrador

Under the Environmental Protection Act, 2002 and its regulations,[18] industrial facilities that release regulated substances must obtain approval from the Minister of the Environment.

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[17] Note that the New Brunswick Clean Air Act has an Administrative Penalties Regulation, which specifies the offenses under the Act for which administrative penalties between $200 and $5,000 per day may be imposed.

[18] Environmental Protection Activity Approval Regulations and Air Pollution Control Regulations.

The regulations contain maximum allowable concentrations of the listed substances. Emissions from stationary sources are measured by maximum allowable concentrations at a point of impingement. Modifications to the activity require a new approval. In issuing a permit under the Act, the Minister may require pollution prevention or rehabilitation plans or apply more stringent standards in environmentally sensitive areas.

B.2.3.10 Prince Edward Island

The provincial Environment Protection Act and its regulations govern the issuance of air quality permits for fuel-burning equipment and industrial sources of air emissions. Provincial Ambient Air Contaminant Ground Level Concentration Standards are used for permitting. Compliance with air quality standards is determined through modeling and point of impingement measurements.

B.3 SUMMARY

In the United States, as a result of experience in emissions cap and trading gained under Title IV, the OTC, and the NO_X SIP call, several of the legal prerequisites for possible cross-border trading with Canada are already in place (e.g., strict monitoring and an infrastructure for collecting emissions data, implementing allowance allocations and trading, and determining compliance). However, it appears that additional U.S. legislative and/or regulatory action may be necessary to authorize cross-border SO_2 and NO_X emissions cap and trading programs.

In Canada, the legal authorities exist that could provide the basis for developing cross-border trading. Federal and provincial governments have legal responsibilities in air quality management and would need to participate in the development of any cross-border emissions cap and trading program. As well, in Canada, regulations would be required to create mandatory emission reduction caps in the electricity sector in addition to regulations that create the basis for cross-border trading, including elements such as monitoring and reporting.

One area that remains to be considered is the recognition of Canadian allowances under U.S. law and U.S. allowances under Canadian law. Currently, affected units in the United States cannot use external (i.e., non-U.S.) allowances to comply with Title IV and SIP obligations. Should Canada and the United States decide to pursue cross-border trading of SO_2 and NO_X allowances, Canadian and U.S. allowances will need to be given equal legal status in both countries so that either could be exchanged freely and used for compliance. Such recognition would be based on consistency across the two countries in key areas such as monitoring, compliance, and banking and may require changes in domestic legislation coupled with international legal instruments by which Canada and the United States formally recognize certain elements of the other nation's program as equivalent to enable international trading of emission allowances.

SECTION C

APPLICABILITY

An emissions cap and trading system is supported by a legal framework in which the coverage (the domain of regulated activities) is precisely defined. Usually, this includes a list of the types of sources (e.g., power generation, industrial boilers), de minimis thresholds (capacity, input, output, and/or emissions rate), and pollutants covered.

This section addresses the issue of which sectors are well matched to a cross-border emissions cap and trading program. Section C.1 provides an overview of the technical and administrative considerations for including or excluding sources. Section C.2 presents an overview of sulfur dioxide (SO_2) and nitrogen oxide (NO_X) sources in the United States and Canada. Section C.3 discusses emission reduction options available for different sources, and Section C.4 describes voluntary opt-in provisions.

C.1 OVERVIEW OF PRINCIPLES

Cap and trade can be an effective way to control emissions from some sectors. The United States has achieved very good results from its cap and trade programs for controlling SO_2 emissions from electric power plants and NO_X emissions from electric power plants and industrial boilers. However, for various practical reasons, not all sectors are as well suited to such a program. In addition, even within an otherwise appropriate sector, there may be certain types of sources that should be excluded for administrative or technical reasons.

"Applicability," as discussed in this section, refers to the technical and administrative considerations that need to be addressed to determine whether a particular kind of source participates in an emissions cap and trading program.

Based on the U.S. experience in determining the applicability of the SO_2 and NO_X emissions cap and trade programs in the electric power and industrial sectors, the key technical considerations include the contribution to emissions and "potential for leakage," measurement capabilities, availability of cost-effective control options, and administrative burdens. These considerations are discussed in more detail below.

C.1.1 Contribution to Emissions and Potential for Leakage

Sources included in a cap and trading program should represent a significant portion of emissions in order to appropriately and adequately address public health and environmental risks associated with SO_2 and NO_X emissions. Further, it is important for the regulating authority to examine and, if necessary, address emission sources that cannot feasibly be included in the cap and trade program, but that could receive shifts in production from emission sources constrained by the cap. Such shifts of production from affected sources to unaffected sources, more commonly called "leakage," could undermine the environmental benefits of the cap.

C.1.2 Ability to Measure Emissions

Sources that participate in a rigorous cap and trading program must have the ability (or capability) to monitor their emissions within a defined level of certainty and comprehensiveness. For example, emissions that are vented to the atmosphere through a stack can be measured with a continuous emission monitoring system (CEMS) to produce accurate, verifiable emissions data.

C.1.3 Availability of Cost-Effective Control Options

Sources included in the program should have a wide range of costs of compliance due to wide economies of scale, variations in compliance options, and other factors to ensure their ability to achieve the reduction goal. Generally, variation in abatement costs promotes competition among control options, stimulates innovative technologies, helps lower compliance costs, and leads to a more robust trading market.

C.1.4 Administrative Burdens

C.1.4.1 Number and Size of Sources

An important criterion in defining the applicability or "mandatory participation" in an emissions trading system (or the domain of regulated activities) is the minimum size of the plant or the unit. This de minimis threshold determines what small units would be exempted from mandatory participation. The threshold also has an implication for the total number of sources in the program.

The determination of a de minimis threshold should take into account, on one hand, the emission monitoring costs and other administrative burdens associated with participation in the system and, on the other hand, the environmental and economic advantages of inclusion. The de minimis threshold should be low enough to minimize leakage. A preliminary and ongoing analysis should examine whether units excluded from the program thereby incur an economic advantage. For instance, the U.S. Acid Rain Program captured the vast majority of emissions using an applicability threshold of 25 MW for existing units. Many units below this threshold were peaking units, or units used to meet requirements during the periods of greatest or peak load on the system. In other words, these smaller excluded units were not in competition with the larger included ones, and there was little risk of leakage or increased production shifting to smaller units from larger ones. In addition, smaller units generally were not significant emitters in this case.

C.1.4.2 Simplicity

It is important to avoid overly complex applicability criteria. Complex criteria make it more difficult and costly for sources and for the regulating authority to determine which sources the program covers. Complex criteria also increase the likelihood of loopholes that may allow significant sources in the same industrial sector to avoid inclusion in the program. To this end, the threshold(s) for determining source applicability should be based on source characteristics that generally remain constant, such as capacity or potential to emit, rather than characteristics that could vary from year to year, such as mass emissions or fuel use. Experience has shown that it is best to minimize changes in an individual source's applicability status. This will ease administration of the program and provide greater certainty to sources for planning and implementation.

However, if the characteristics of the source excluded from the program change so that the source is now essentially the same as other sources that are already in the program, it may be desirable to require that source to enter the program. This approach may prevent a source from avoiding the program by only temporarily adopting characteristics that would exclude it from the program.

C.1.5 Geographic Scope

An emissions cap and trading program should be applied at a scale and scope appropriate to achieve the environmental goal. The development of the U.S. Acid Rain Program as a nationwide program is a case in point. The evidence of long-range transport of SO_2 and NO_X emissions from the Midwest to the Northeast suggested that emission impacts could extend well beyond the area where they originated. Damage from acid deposition was also evident, particularly in the Northeast. In western regions, deposition levels were below what would cause widespread concern, with the exception of high-elevation alpine lakes in certain areas. However, rapid growth projections suggested that emissions would be rising in the future. Forecasts and trends, coupled with the knowledge that western ecosystems were considered sensitive to acid rain, pointed to the need to include the West in the Acid Rain Program. Furthermore, SO_2 presented not only public health and environmental impact concerns, but also visibility concerns. Limiting the growth of acid rain precursors supported efforts by groups such as the Grand Canyon Visibility Commission to mitigate visibility impacts. Finally, the electric power sector operates on a continental, national, and regional grid. The ability to shift load (and emissions) to potentially excluded sources always needs to be considered in placing controls on this sector. All these reasons contributed to defining the geographic scope of the U.S. acid rain emissions cap and trading program.

C.1.6 Equity

As mentioned above, the regulating authority should give careful consideration to the economic competitiveness of businesses and the effect on markets of including or excluding certain industries from a trading system. Fairness relative to emission reduction potential is another consideration for the regulating authority in weighing the feasibility of an emissions cap and trading program. [1]

C.2 SO_2 AND NO_X SOURCES AND DISTRIBUTION OF FUEL TYPES

As discussed previously, SO_2 and NO_X are pollutants that cause acid rain and numerous other human health and environmental impacts. Furthermore, both can be transported over long distances, expanding the potential area for impacts far beyond the source area where they were emitted. One of the major causes of SO_2 and NO_X emissions is the combustion process (burning of fuels). [2]

C.2.1 National Overview of Sources

C.2.1.1 United States

In 2002, as stated in Section A on Air Quality, U.S. SO_2 emissions totaled some 15.8 million tons. The primary source of these SO_2 emissions (~70 percent) is fuel combustion from electric generating units (EGUs) due to burning of sulfur-containing fuels, such as coal and oil. Figure A-9 (in Section A) shows the contribution to emissions from various sources in the United States according to the most recent data from the U.S. National Emissions Inventory (NEI). Fuel combustion by industrial sources accounts for 15 percent of total SO_2 emissions. [3]

The two primary sources of the 21.2 million tons of NO_X emissions in the United States in 2002 are transportation (on-road combustion) and EGUs. As shown in Figure A-9, these two sources represent three-quarters of total NO_X emissions in 2002. EGUs account for approximately 22 percent of these total NO_X emissions. Industrial source fuel combustion accounts for some 14 percent of total NO_X emissions.

In the United States, metal smelting and other industrial processes release significant, but relatively smaller, quantities of SO_2 and NO_X. [4] Industrial processes include emissions that are produced from the industrial process itself and are not directly a result of energy consumed during the process. These non-energy-related industrial activities include, for example, iron and steel production and cement manufacturing. According to the most recent ambient air pollutant trends data from the NEI (2002), industrial processes as a whole contribute approximately 9 percent of SO_2 emissions, while specific processes such as metal processing account for approximately 2 percent of total 2002 SO_2 emissions. Similarly, industrial processes as a whole constitute 5 percent of 2002 NO_X emissions.

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[1] U.S. EPA, "Tools of the Trade," **http://www.epa.gov/airmarkets/international/tools.pdf**

[2] Sulfur is released from the fuel source and combines with oxygen in the air to form SO_2. Similarly, during the combustion process, nitrogen in the atmosphere combines with oxygen and water to form several NO_X compounds.

[3] The U.S. National Emissions Inventory with average annual emissions data for SO_2 and NO_X from 1970 to 2002 is available at **http://www.epa.gov/ttn/chief/trends/index.html**.

[4] Ibid.

C.2.1.2 Canada

In 2002, as stated in Section A, Canadian SO_2 emissions totaled some 2.6 million tons. [5] Figure A-9 shows the contribution to emissions from various sources. In contrast to the United States, the primary single source of SO_2 emissions (~30 percent) in Canada is non-ferrous mining and smelting. Fuel combustion from EGUs due to burning of sulfur-containing fuels, such as coal, is the second largest single source of SO_2 emissions (~25 percent). Other industrial sources account for 40 percent of total SO_2 emissions.

In Canada, the primary source of the 2.8 million tons of NO_X emissions is transportation (~60 percent). [6] As shown in Figure A-9, fossil fuel combustion from the electricity sector is one of the largest stationary sources of NO_X (~11 percent). Various industrial sectors also contribute to significant NO_X emissions. As a whole, these sectors account for approximately 25 percent of Canada's total emissions.

C.2.2 Electricity Generating Sector

Fuel type plays a key role in the amount of SO_2 and NO_X emissions generated during combustion to generate electricity. For example, emissions from uncontrolled coal-fired units are much greater than emissions from natural gas-fired units per unit of electricity produced.

C.2.2.1 United States

Coal-based fuel combustion from electric utilities is the largest single source of SO_2 emissions in the United States. In 2002, electric utilities in the United States produced some 2,549 terrawatt hours (TWh) of electricity, with slightly more than 50 percent coming from coal. [7] Electric utilities accounted for 62 percent of electricity generation, while nonutility generators accounted for the remaining generation. Most power plants are located east of the Mississippi River in the United States. Figure C-1 shows the mix of fuels used to generate electricity in each state. According to the map, the fuel mix varies by region. In the Midwest, most generation is coal-based. In contrast, the mix of fuels used to generate electricity in Texas is approximately 50 percent gas, 37 percent coal, and 10 percent nuclear (with the remaining 3 percent from other sources). The U.S. fuel mix is not projected to change significantly over the next 15 years. [8]

The mix of U.S. fossil fuel-fired EGUs at electric utilities consists primarily of steam units, turbines, and combined cycle units. Among Acid Rain Program units, [9] 52 percent are steam units, while 30 percent are gas-fired turbine units. The remaining units consist of combined cycle units (16.3 percent) and oil-fired turbines (1.6 percent). More information on facility attributes is available on the U.S. Environmental Protection Agency's (EPA) Clean Air Markets Division (CAMD) Web site at **http://cfpub.epa.gov/gdm/**. Units range in size from 25 MW to 1,300 MW.

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[5] Preliminary data from Environment Canada.

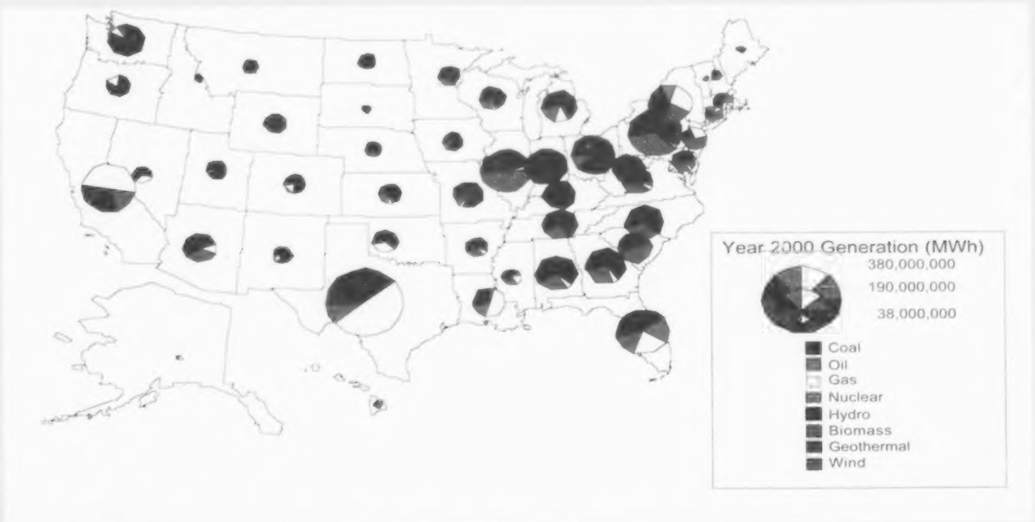
[6] Ibid.

[7] Total electricity generation in the United States was 3,858 TWh from all energy sources. Energy Information Administration (2002). "Electricity Quick Stats," updated 01/31/2005, **http://www.eia.doe.gov/neic/quickfacts/quickelectric.htm**, accessed 1/31/05.

[8] U.S. EPA (2004). "Technical Support Document: Analysis in Support of the Clean Air Interstate Rule Using the Integrated Planning Model," **http://www.epa.gov/air/cleanairinterstaterule/pdfs/tsd.pdf**, May 28, 2004, accessed 12/16/04.

[9] These percentages are based on data provided by the Emissions Monitoring Branch of the Clean Air Markets Division (CAMD).

Figure C-1 Fraction of Electric Generation by Fuel Type (2000)



Source: EPA, **http://www.epa.gov/cleanenergy/egrid/samples.htm#egridmaps**

C.2.2.2 Canada

In Canada, a large proportion of fuel combustion is for the generation of electricity. Electric utilities generate over 90 percent of the nation's total electricity, while the remainder is generated at various industrial plants, primarily for on-site use. In 2002, 580 TWh of electricity was generated.[10] Figure C-2 illustrates the mix of fuel types used to generate electricity in each region. At the national level, electricity generation in Canada is dominated by hydroelectricity, which produces 60 percent of the nation's electricity. While the combustion of fossil fuels for electricity generation accounts for only a quarter of Canada's overall total, in certain regions fossil fuels play a prominent role.

In Canada, approximately three-quarters of fossil fuel-fired electricity is generated from the combustion of coal. The five major coal-burning provinces are Alberta, Saskatchewan, Ontario, New Brunswick, and Nova Scotia. Additional generation comes from oil and orimulsion in the Atlantic and northern regions and from natural gas in the west.

In Canada, the mix of fossil fuel-fired EGUs at electric utilities is composed of steam units, gas turbines, and internal combustion units. Steam units, at over 85 percent,[11] make up the largest percentage by capacity of these fossil fuel-fired units. Within the 12 major electric utilities across Canada, there are 35 steam plants with approximately 100 active boilers. These units range in size from 1.5 MW to 510 MW, with an average size of approximately 240 MW. Many of these units fire bituminous, subbituminous, or lignite coal. There are also some oil-, gas-, and orimulsion-fired units.

Combustion turbines (as simple or combined cycle) make up 12 percent[12] of the capacity from electric utilities. There are approximately 100 units ranging in size from 1 MW to 110 MW, with an average size of 40 MW. These units combust oil and natural gas. The choice of fuel is generally dependent upon the region. Over 90 percent of the capacity of oil-fired combustion turbines is in Quebec and the Atlantic provinces. These units, located in the east, combust either light fuel oil or diesel. Typically, these units are

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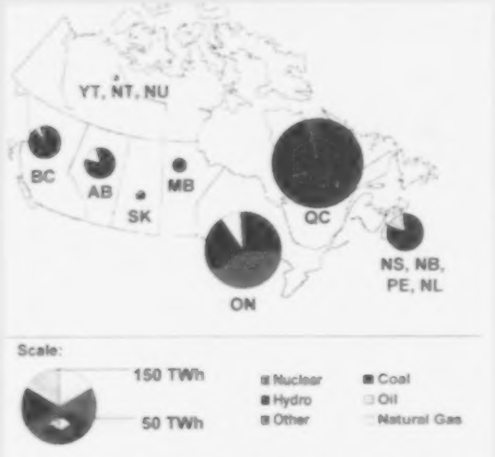
[10] Statistics Canada (2004). "Electric Power Generation, Transmission and Distribution, 2002," Catalogue no. 57-202-XIB.

[11] Statistics Canada (2001). "Electric Power Generating Stations, 2000," Catalogue no. 57-206-XIB.

[12] Ibid.

Figure C-2 **Total Electricity Generation by Fuel Type, 2002**



Source: Statistics Canada (2004). "Electric Power Generating Stations, 2002," Catalogue no. 57-206-XIB; Statistics Canada (2003). "Report on Energy Supply-Demand in Canada, 2002," Catalogue no. 57-003-XIB.

utilized for peaking or backup power and not for base load generation, generally operating fewer than 100 hours per year. As a result, their overall contribution to generation is extremely small. For example, in Atlantic Canada, these plants contribute to less than 1 percent of the region's generation.

The majority of natural gas-fired combustion turbines (over 95 percent by capacity) are located in Ontario, Saskatchewan, and Alberta. While some of these units may be used for base load generation, they also contribute only a small amount of the total generation. For these three provinces, electricity production from gas-fired turbines is less than 10 percent of each province's total generation.

The remaining 3 percent [13] of capacity of fossil fuel-fired electric utilities comprises internal combustion units, which mainly combust oil, but natural gas and waste gas are also used. These will not be considered further in this discussion due to their minor impact on air emissions and the small size of the units (typically <1 kilowatt).

C.2.3 Other Industrial Sectors

As discussed in Section C.2.2.1, the U.S. SO_2 emissions cap and trading program targets the primary and largest contributing sector to emissions: the electric power sector. This maximizes coverage of emissions and also ensures efficiency, given the variation in abatement costs of different units.

Because both U.S. emissions cap and trading programs focus on the electric power sector, that is a logical place to begin studying the feasibility of a cross-border U.S.-Canada emissions cap and trading program. However, industrial sectors that are important contributors of SO_2 and NO_X emissions may be suitable for inclusion in the kind of cap and trading program being contemplated by this study.

The following discussion does not imply that industrial sectors ought or ought not to be included. Though they are large stationary sources that contribute to emissions, many other economic, environmental, and social considerations beyond the scope of this study would need to be explored.

C.2.3.1 United States

According to data collected by EPA, some 340 industrial sources in the United States are affected under the NO_X Budget Trading Program. These largely include industrial boilers (48 percent of industrial sources), but also petroleum refineries (16 percent), pulp and paper mills, cement kilns, and iron and steel mills. In 2004, these sources represented nearly 13 percent of all State Implementation Plan (SIP) sources and approximately 7 percent of the NO_X emissions under the SIP call. [14]

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[13] Ibid.

[14] This number represents the most current numbers in the EPA-CAMD database as of June 2005 (updated from U.S. EPA (2003). "NO_X Budget Trading Program: 2003 Progress and Compliance Report," p. 10). Note: The Emissions Monitoring Branch of EPA's CAMD defines industrial sources as industrial boilers not classified under the source category of Electric Utility, Small Power Producer and Cogeneration, or that meet State industrial source classification.

C.2.3.2 Canada

Industrial Boilers

It is estimated that there are 350,000 to 600,000 nonutility boilers in Canada.[15] These are found in several different industries, including pulp and paper, chemical, oil refining, iron and steel, mining, and commercial and institutional sectors. Of these, approximately 200 to 400 have maximum rated heat input capacities greater than 250 million British thermal units (mmBtu)[16] per hour (the minimum size for inclusion in the U.S. NO_X Budget Trading Program).[17] These units are widely dispersed across the country in relation to the industrial sector in which they belong. For example, there are a large number of pulp and paper boilers in British Columbia.

It is difficult to ascertain the SO_2 and NO_X emission contributions of industrial boilers within the given size range (>250 mmBtu/hour). Further information is required on this sector to determine its feasibility for inclusion in a cross-border emissions cap and trading program.

Smelters

As mentioned previously, Canadian smelters play a significant role in Canada's SO_2 emissions. These facilities are primary producers of cobalt, copper, lead, nickel, and zinc, along with a variety of co-product metals. There are 12 base metals metallurgical complexes located in British Columbia, Alberta, Manitoba, Ontario, Quebec, and New Brunswick.

The smelters release approximately 30 percent of the nation's SO_2 emissions. These emissions are regional and play a major role in Manitoba, Ontario, and Quebec.

Industrial boilers exist at smelter facilities in Canada, but they play a minor role in the air emissions produced by the facilities as a whole. The industrial processes used in the extraction and refining of base metals are the dominant contributors to air emissions. These processes are specific to the type of metal produced. Fugitive emissions from smelters—that is, emissions not directly released through a stack—contribute to total emissions. This may lead to difficulties within an emissions trading system (e.g., continuous monitoring of emissions). More information is required on smelter emissions to determine the feasibility for inclusion in a cross-border emissions cap and trading program.

Cement Manufacturing

The cement manufacturing industry has also been considered for inclusion in an emissions trading system, since this sector is one of Canada's top 10 industrial sectors for the emission of both NO_X and SO_2 and it is also a sector whose emissions can be monitored at the unit level with CEMS. (According to EPA, three cement kilns in New York successfully participate in the U.S. NO_X Budget Trading Program under the NO_X SIP call.)

In Canada, the cement manufacturing sector comprises seven companies operating 16 plants with a total of 25 operational kilns. Emissions from this sector are regional and play a major role in British Columbia, Alberta, Ontario, and Quebec.

While emissions are generated in all steps of the cement manufacturing process, the combustion of fuel in the kiln makes up 75 percent of the total emissions from this sector. One factor influencing the amount of emissions is the fuel type. Several types of fuel are used in the cement industry: coal and petcoke account for approximately 60 percent of the total fuel consumed; other fuels include natural gas, petroleum products, and wastes.

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[15] Working Group #1 for the Multistakeholder Steering Committee for Initiative N306 (1996). "Background Document for the Development of a National Guideline for NO_X Emissions from New or Modified Commercial/Industrial Boilers and Process Heaters," p. A-1.

[16] One Btu = 1.06 kilojoules.

[17] Based on estimates from 1) Jaques Whitford (2004). "Industrial Boilers Database for Boilers > 250 mmBtu/hr" and 2) Working Group #1 for the Multistakeholder Steering Committee for Initiative N306 (1996). "Background Document for the Development of a National Guideline for NO_X Emissions from New or Modified Commercial/Industrial Boilers and Process Heaters."

A kiln's process type—wet or dry—also influences the amount of emissions. The addition of preheaters and precalciners represents more recent technologies that have increased process control and plant efficiency, thereby reducing fuel consumption. The dry process has become more prevalent than the traditional wet process; in Canada, only one wet plant (with two kilns) still operates. Of the 23 remaining units, 12 are conventional dry kilns, five are preheater kilns, and six are preheater-precalciner kilns.

C.3 EMISSION REDUCTION OPTIONS FOR SO_2 AND NO_X

Sources participating in an emissions cap and trading program can employ one or more of the following alternatives for meeting emission requirements: reducing on-site emissions, buying excess allowances from other sources that have allowances to sell, or using banked allowances from a previous year. This section describes the options that may be available to different types of sources for achieving on-site emission reductions.

Typically, sources have two types of options available for controlling emissions: primary measures and postcombustion controls. Primary measures include:

- Process optimization, where the emphasis is on increased energy efficiency and productivity.
- Selection of different fuels or raw materials with lower emission generating characteristics.
- Combustion controls, where the emphasis is on reducing emissions formation.

Postcombustion options involve installation of emission control technologies that remove pollutants from the flue gas stream, such as scrubbers used for SO_2 removal. Often, source facilities use a combination of both primary and postcombustion techniques.

Many factors, including age, size, usage, and location of an existing plant, require consideration when selecting one of these options.

C.3.1 Electric Generating Units

One of the most common methods for electric utility steam plants to reduce SO_2 and NO_X emissions at the source is to install pollution control equipment. The use of low-NO_X burners and/or the use of overfire air are common combustion modification technologies for NO_X control on boilers firing a variety of fuels. On gas turbines, dry low-NO_X combustors, water injection, or steam injection systems are used to reduce NO_X. The most commonly used postcombustion technology options include wet or semidry flue gas desulfurization (FGD) systems for SO_2 removal and selective catalytic reduction (SCR) or selective noncatalytic reduction (SNCR) for NO_X removal. FGD generally reduces SO_2 emissions by 90 to 95 percent depending on the technology, while SCR and SNCR systems are typically capable of reducing NO_X emissions by more than 90 percent and 30 to 60 percent, respectively, depending on unit and fuel characteristics.[18]

Other options that are available for reducing on-site emissions include:

- Fuel blending.
- Fuel switching—from high-sulfur to lower-sulfur fuel; from coal or oil to natural gas.
- Repowering—replacing a boiler in a steam plant with a gas turbine and heat recovery steam generator train, or more efficient IGCC.
- Improving energy and operational efficiency, which will reduce emissions of both SO_2 and NO_X.

A retrospective look at compliance strategies by EGUs under the U.S. Acid Rain Program shows that postcombustion controls such as scrubbing accounted for nearly 37 percent of emission reductions in 2001. Most of these reductions came from new scrubbers installed on 30 units, located primarily in the Midwest. The remaining 63 percent of reductions came from coal-fired units switching to lower-sulfur coals.[19] Fuel switching to low-sulfur coal became a cost-effective abatement option with the significant decline of rail transport costs in the late 1980s and early 1990s. This trend may not continue into the future.

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[18] EPA-CAMD (2004). "IPM Documentation Report," Section 5: Emission Control Technologies, Exhibit 5-1, v.2.1.9. Conversation with S. Khan, January 31, 2005.

Under the NO_x Budget Trading Program,[20] sources also report pollution control information, including installation dates, in monitoring plans submitted to EPA. As of April 2005, there were 122 coal-fired units using SCR controls that report emissions. Fifty-three coal-fired units, of which nine are industrial units, reported installing SNCR. Most of these installations occurred outside of the Ozone Transport Commission (OTC) region in the northeastern United States. However, since October 2002, sources within the original OTC states have installed SCR controls on fifteen units with approximately 8171 MW capacity and SNCR on thirteen units with about 2295 MW capacity. These data indicate that the implementation of the NO_x Budget Trading Program appears to have been an impetus for many units to reduce their NO_x emissions through the use of add-on controls, especially in the states where significant reductions are needed to comply with the NO_x Budget Trading Program.[21]

C.3.2 Industrial Boilers

Many of the options available to steam plants in the electric utility sector for emission reductions are also available to industrial boilers. The applicability of these control options is conditional on several factors, including boiler size. Postcombustion control technologies, such as FGD, may be realistic options for larger electric utility boilers, but smaller industrial boilers may choose less costly alternatives. The likely options for on-site reduction of emissions from industrial boilers include the following (depending on size of boiler):

- Low-NO_x burners for NO_x control.
- Fuel switching, where possible, for SO_2 control.
- Improved boiler performance through control optimization and good combustion practices, which will reduce emissions of both NO_x and SO_2.

As mentioned above, under the NO_x Budget Trading Program, nine industrial units have reported installing SNCR technology. Approximately 70 industrial units have reported using low-NO_x burners.[22] Many industrial units reporting add-on control technologies (SCR) have combined these with other control technologies (combustion modifications and fuel switching) for maximum effect.

An additional factor affecting the application of potential control options is integration within an industrial process. In some facilities, industrial boilers use fuel derived from their specific industrial processes at little or no cost. In these cases, it is unlikely that switching to, and therefore purchasing, a more environmentally benign fuel would occur. Industrial boilers in the pulp and paper industry, for example, often combust spent pulping liquor.

C.3.3 Smelters

One option available to the smelter industry for SO_2 control is the installation of a wet scrubbing system. An acid plant may follow this system, where the SO_2 recovered from the FGD is converted into sulfuric acid, a product with further commercial value. A second option is the modernization of the smelter process. This is specific to the type of metal being produced and may not be available to all facilities. NO_X emissions from this sector are relatively minor.

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[19] Ellerman, A.D. (2003). "Lessons from Phase 2 Compliance with the U.S. Acid Rain Program," MIT Center for Energy and Environmental Policy Research. Cambridge, p. 5. **http://web.mit.edu/ceepr/www/2003-009.pdf**

[20] The NO_x Budget Trading Program is a cap and trading program for large EGUs and large industrial boilers, turbines, and combined cycle units within NO_x SIP call states. EPA provided these states with a model cap and trading rule (the NO_x Budget Trading Program) to achieve the emission reductions set forth in the NO_x SIP call in a highly cost-effective way.

[21] U.S. EPA (2004). "NO_x Budget Trading Program: 2003 Progress and Compliance Report," pp. 20-21.

[22] This is from preliminary data collected by the Emissions Monitoring Branch of the U.S. EPA's CAMD as of October 2004.

C.3.4 Cement Kilns

Both primary measures and postcombustion control options may be used to reduce SO_2 and NO_X emissions from cement kilns. Primary measures for SO_2 control include the selection of low-sulfur fuels and raw materials with low pyrite content, as well as lime addition. Primary measures for NO_X control include changes to temperature and excess air, mineral additions, the selection of raw material, and combustion modification via flame cooling, low-NO_X burners, staged fuel/air combustion, and mid-kiln firing.

Postcombustion methods include dry or wet scrubbing technologies for SO_2 control and SCR or SNCR for NO_X control.

C.4 OPT-IN PROVISIONS

In general, the applicability criteria for an emissions cap and trading program are designed to include those sectors of emission sources that are most appropriate, taking into account policy, control cost, monitoring, and other considerations. However, it is possible to include provisions that allow individual sources not covered by these applicability criteria to voluntarily "opt in" to the program. Theoretically, these sources may have cost-effective emission reduction opportunities that warrant the expense of meeting the monitoring and other requirements associated with the cap and trading program. If policymakers allow opt-ins, the regulator would have to define the program entry requirements for such sources (including monitoring requirements, such as having CEMS) and the method for allocating allowances for such sources. Monitoring requirements for an opt-in source must be the same as those for sources that are required to be in the program in order to ensure that the reductions achieved are real, verifiable, and comparably valued.

While voluntary opt-in provisions may reduce costs to affected sources, such provisions raise some other issues. Sources may decide to opt in and take advantage of allowance allocations that are greater than what their emissions would have been if they were not participating in the cap and trading program. In some cases, they may opt in and then take measures to reduce emissions that would have occurred anyway, regardless of participation in the program. In addition, sources may opt in, reduce their utilization by shifting utilization to other sources not subject to the trading program, and have freed-up allowances to sell. Unless the regulating authority can make an allowance allocation at a level that is at or below "business as usual" and takes account of reduced utilization, extra allowances will be introduced into the system and will undermine the environmental effectiveness of the emissions cap and trading program.[23]

C.4.1 Acid Rain Program Opt-in Provision

Recognizing that additional SO_2 emission reduction opportunities existed in the industrial sector, Congress established the Opt-in Program under section 410 of the Clean Air Act Amendments of 1990. The Opt-in Program allowed sources not required to participate in the Acid Rain Program the opportunity to enter the program on a voluntary basis and receive their own SO_2 allowances. Opt-in sources faced the same requirements as other sources in the program. It was expected that the participation of these additional sources would reduce the cost of achieving the roughly 10 million ton reduction in SO_2 emissions mandated under the

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[23] See U.S. EPA (2003), "Tools of the Trade," **http://www.epa.gov/airmarkets/international/tools.pdf**, for continued discussion.

Clean Air Act by providing lower cost reduction opportunities. As participating opt-in sources reduced their SO_2 emissions at relatively low cost, their reductions—in the form of allowances—would be available to electric utilities where emission reductions were more expensive. The program was further intended to offer combustion sources financial incentives to voluntarily reduce SO_2 emissions. By reducing emissions below the allowance allocation, an opt-in source would have unused allowances, which it could then sell in the SO_2 allowance market.[24] However, only 11 units from four sources actually chose to opt in to the Acid Rain Program. Furthermore, research on the Acid Rain Program (Ellerman et al., 2000) suggests that these sources were induced to voluntarily join the program under the opt-in provisions because of overly generous allowance allocation formulas. Opt-ins using these provisions achieved very few additional emission reductions.

C.4.2 U.S. NO_X Budget Trading Program Opt-in Provisions

Most states within the NO_X SIP call area have also adopted the opt-in provisions outlined in the NO_X Budget Trading Program model rule (40 CFR Part 96). Similar to opt-in provisions under the Acid Rain Program, once a unit opts in to the program, the unit is subject to the same compliance, monitoring, and reporting requirements that apply to units required to participate in the trading program. However, only boilers, combustion turbines, or combined-cycle systems can opt in to the NO_X Budget Trading Program. In order to opt in, units must submit an application to their state permitting authority for a NO_X budget opt-in permit that includes a monitoring plan. This plan is reviewed and must be determined to be sufficient by the relevant state permitting authority and EPA. If the plan is sufficient, the source must monitor and report its emissions rate and heat input for a full control period (ozone season), in accordance with 40 CFR Part 75, in order to establish the baseline heat input and baseline NO_X emission rate. Subsequently, after the application is approved, the relevant state permitting authority will issue the unit a permit and allocate the appropriate amount of allowances, calculated for a given control period as:

- The lesser of the unit's baseline heat input or actual heat input for the immediately prior ozone season multiplied by
- The lesser of the unit's baseline emissions rate or the most stringent state or federal emissions limitation applicable to the unit.

The opt-in program under the SIP call will be evaluated as data are collected.

C.4.3 CAIR Program Opt-in Provisions

The opt-in provisions in the Clean Air Interstate Rule (CAIR) trading programs are similar to the opt-in provisions in the NO_X Budget Trading Program. Opt-ins are limited to boilers, turbines, or other fossil fuel-fired combustion devices that vent all emissions through a stack and are able to meet Part 75 emission monitoring and reporting requirements. There are two mechanisms that the states can use to allow an opt-in, and they may choose one or both. The first effectively requires—through reduced allowance allocations—a 30 percent reduction in emissions, and the second has special provisions and requirements for sources that repower with qualifying technologies.

C.5 SUMMARY

While in the United States, the primary source of SO_2 emissions, and a major contributor of NO_X emissions, is fuel combustion from EGUs, in Canada other sectors in addition to EGUs are key contributors to SO_2 (base metals smelting) and NO_X emissions (industrial sources).

In general, harmonization of applicability in terms of coverage of sources and sectors is desirable, rather than required. For example, EGUs should be included in any SO_2 or NO_X cross-border trading program because they are an important contributor to both SO_2 and NO_X emissions in both countries. Currently, in both the U.S. Acid Rain Program and NO_X Budget Trading Program, the EGUs are the main participants, while the NO_X Budget Trading Program includes industrial sources such as large industrial boilers (e.g., petroleum refineries, pulp and paper mills, cement kilns, and iron and steel mills). The CAIR trading programs are generally limited to EGUs. However, industrial sources play a relatively larger role in SO_2 and NO_X emissions in Canada than in the United States. These sources, including base metals smelters, need to be examined further for potential inclusion in a Canada-U.S. cross-border emissions cap and trading program, as there are some concerns about the ability to measure emissions rigorously and in an equivalent manner to the electricity sector. To the extent that some aspects of applicability would not be harmonized, there should be further analyses of economic consequences and international trade issues before a decision is made as to allowable differences.

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[24] See **http://www.epa.gov/airmarkets/arp/overview.html#optin** for more information.

Opt-in provisions could be considered, in the context of a cross-border emissions cap and trading program, to allow sources that fall outside of the applicability bounds the option to participate in the program. However, additional provisions for these units would need to be specified in the program to ensure the integrity of the emission caps and to minimize administrative burden. These provisions would need to address issues such as: requiring the same emissions monitoring as for units required to be in the program; avoiding the allocation of allowances for emissions that already have been reduced; and minimizing allocations for emissions that would be reduced without the unit opting in or that may be shifted (through utilization shifting) to units not subject to the trading program. These issues need to be addressed effectively but in a way that does not impose unreasonable administrative burden.

C.6 REFERENCES

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SECTION D

EMISSIONS MONITORING AND REPORTING

Emissions monitoring and reporting are the backbone of emission cap and trading programs. Experience has shown that well-defined, rigorous monitoring and reporting procedures that measure mass emissions as accurately, consistently, and objectively as possible are a necessary condition for creating a high level of confidence in the value of allowances. The more accurate and complete the method of emissions measurement, the less risk and uncertainty there are associated with the emission tonnage represented by an allowance, the more value they have as tradable commodities, the lower the transaction costs of trading, and hence the more efficient the market.

This section discusses emissions monitoring and reporting in the United States and Canada and highlights the need for harmonization of the two regimes under a cap and trading program. Section D.1 illustrates the fundamental requirements of emissions monitoring and reporting under an emissions cap and trading program. Section D.2 discusses U.S. emissions monitoring and reporting under the sulfur dioxide (SO_2) and nitrogen oxide (NO_X) trading programs, focusing on 40 CFR Part 75 – Continuous Emission Monitoring. Section D.3 discusses the Canadian emission monitoring and reporting specifications in Report EPS 1/PG/7. Finally, Section D.4 provides an analysis of the previous sections, highlighting the areas where the two monitoring regimes need to be consistent in order to implement a successful cross-border emissions cap and trading program.

D.1 PRINCIPLES

Emission monitoring requirements for an emissions cap and trading program must be rigorous for several reasons:

- To ensure that emissions from all sources are consistently and accurately measured and reported.
- To verify that a ton of emissions from one source is equal to a ton of emissions from any other source.
- To address the need to collect and evaluate large amounts of data quickly.
- To ensure that emission values are produced for every unit operating hour, i.e. to ensure that all emissions are counted.
- To verify that emission reduction goals are achieved by ensuring that emissions do not exceed allowances.

To ensure the success of an emissions cap and trading program, the program must meet several overarching goals in addition to rigor. These include accountability, transparency, predictability, consistency, and flexibility.

D.1.1 Accountability

An emissions cap and trading program must include a framework of oversight and enforcement that will hold participants accountable for all their emissions and ensure compliance with the program's requirements. The basis of accountability is the accurate measurement and verification of emissions and the rigorous and consistent enforcement of penalties for fraud or noncompliance. The regulating authority can facilitate accountability through clear rules that are not unnecessarily complicated.

D.1.2 Transparency

Transparency refers to the full and open disclosure of relevant public and private decisions, such as establishing the rules and regulations for a trading program and determining whether an emissions source is in compliance. Transparency is important to a well-functioning cap and trading program, in terms of both its design and its operation. Transparency of the design process can promote public

Table D-1 Essential Measurements Required by U.S. Emission Cap and Trading Programs

Program	Affected sources	Parameter measured (units)	Accounting period
Acid Rain Program	Fossil fuel-fired electric generating units (EGUs) and other combustion sources that opt in to the SO_2 emissions cap and trading program	SO_2 (tons)	Annual
NO_x Budget Trading Program	EGUs, large industrial boilers, other industrial sources (e.g., cement kilns, process heaters), and units that opt in to the NO_x emissions cap and trading program	NO_x (tons)	Ozone season [1]

acceptance and confidence in the emissions cap and trading program.

Providing public access to source-level emissions and allowance data also promotes confidence in the program and provides an additional level of scrutiny to verify enforcement and encourage compliance. In some jurisdictions these data are classified as confidential, and legal changes may be required to make them publicly available.

D.1.3 Predictability and Consistency

Predictability and consistency in the design and application of program rules are important principles for an effective emissions cap and trading program. They help create the right circumstances to encourage innovation and lower costs. With a cap and trading program, emission sources have an incentive to find better and lower-cost opportunities to reduce emissions. This incentive depends upon long-term, predictable, and consistent rules that affect the economic value of emission reductions.

D.1.4 Flexibility

Although program rules must be predictable and consistent in their design and application, they must also have flexibility. The framework must include options to accomplish the overall data quality objective of the program. Such options allow the source to choose the monitoring approach that best fits its operation. This minimizes the effective cost of monitoring. New information is continually being made available, stressing the importance of flexibility in the program rules.

D.2 U.S. MONITORING AND REPORTING

In the United States, 40 CFR Part 75 – Continuous Emission Monitoring establishes requirements for continuous air emissions monitoring and reporting for large power plants and industrial sources in the Environmental Protection Agency (EPA) Acid Rain Program and the NO_x Budget Trading Program. Under the Acid Rain Program, large industrial sources are included on a voluntary basis only, in contrast to their inclusion in the NO_x Budget Trading Program.

Table D-1 illustrates the essential monitoring measurements required by the Acid Rain Program and the NO_x Budget Trading Program and gives the accounting period for each. Note that Acid Rain Program sources are also required to continuously monitor and report carbon dioxide (CO_2) mass emissions under section 821 of the Clean Air Act. However, measurement of CO_2 mass emissions is not essential for an effective SO_2 or NO_x trading program.

The Part 75 rule specifies the types of monitoring systems that may be used for the required measurements, as well as the operation and maintenance requirements,

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[1] The ozone season extends from May 1 through September 30.

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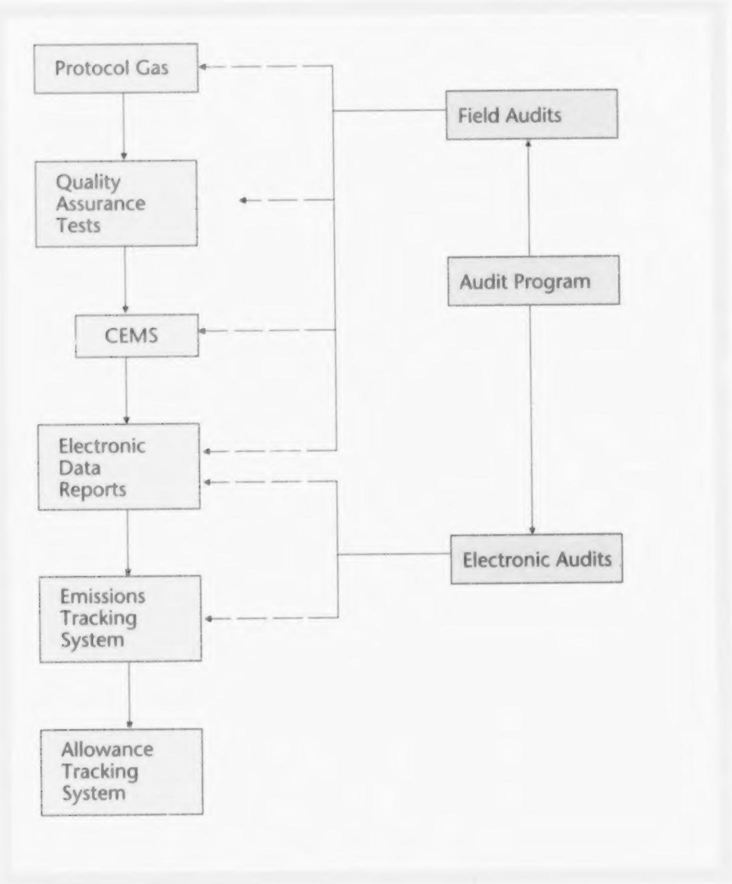
Figure D-1 Overview of Continuous Emission Monitoring under Part 75


Protocol Gas
Quality Assurance Tests
CEMS
Electronic Data Reports
Emissions Tracking System
Allowance Tracking System
Field Audits
Audit Program
Electronic Audits

quality assurance/quality control (QA/QC) requirements, and record-keeping and reporting requirements. Continuous emission monitoring systems (CEMS) must be used unless an affected unit meets the requirements for an alternative to CEMS.

Figure D-1 depicts the major links in the data quality chain for a CEMS. The process starts with ensuring that the gas standards used to calibrate and test the monitoring equipment are accurate. To this end, EPA has adopted a traceability protocol for the certification of gaseous calibration standards. [2] The source must then conduct the necessary QA tests, following all appropriate procedures, and report the results of those tests in a timely and accurate manner. These QA activities are conducted initially for monitoring system certification and then on an ongoing basis, to ensure that the monitoring systems continue to measure the emissions accurately.

Once the continuous emission monitoring (CEM) data are quality-assured, the next step is to ensure that the data are accurately recorded by a data acquisition and handling system (DAHS) and appropriately reported in a standardized format in an electronic data report (EDR). The EDRs are submitted quarterly to EPA for review, and the emissions data are used for accounting purposes in the cap and

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[2] "EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards," September 1997, EPA-600/R-97/121.

Table D-2 Part 75 Monitoring Options

If an affected unit is classified as a...	Part 75 provides these monitoring options...			
	Basic CEMS provisions (75.10-18)	Appendix D method[3]	Appendix E method[4]	LME method[5] (75.19)
Coal-fired unit	✓			
Non-peaking oil- or gas-fired unit	✓	✓		✓
Peaking oil- or gas-fired unit	✓	✓	✓	✓

trading program. EPA provides the necessary data management systems and tools to:

- Check the format of the emissions data and QA tests submitted in the EDRs.
- Recalculate the emissions and QA test results from the raw data.
- Track emissions and allowance transfers.

The integrity of the overall trading program can break down anywhere along this chain of activities. Therefore, EPA relies on a combination of electronic and field audits to verify overall data integrity.

D.2.1 Monitoring Options

The Part 75 rule provides several monitoring options. The available options depend on how each unit is classified in terms of the type of fuel burned, the utilization of the unit, and the unit's potential emissions. Part 75 has a set of basic continuous monitoring provisions that apply to all units. These basic provisions require CEMS for all monitored parameters. However, if a unit is classified as oil-fired or gas-fired, alternatives to CEMS are available for some or all monitored parameters. These alternatives are known as "excepted methods" and are found in Appendices D (for gas- and oil-fired units) and E (for gas- and oil-fired peaking units) of Part 75 and in section 75.19 (for low mass emission (LME) units). This regulatory flexibility allows compliance to be achieved at a lower cost in many instances, without compromising the integrity of the trading programs.

The Part 75 monitoring options are summarized in Table D-2 and are discussed in Sections D.2.1.1 through D.2.1.4 below. Sections D.2.1.5 and D.2.1.6 discuss monitoring methods for industrial sources and alternative monitoring systems, respectively.

D.2.1.1 Continuous Emission Monitoring (CEM)

A CEMS consists of all the equipment needed to measure and provide a permanent record of the emissions from an affected unit. Examples of CEMS components include:

- Pollutant concentration monitors (e.g., SO_2 or NO_X monitors).
- Diluent gas monitors, to measure percent oxygen (O_2) or percent CO_2.
- Volumetric flow monitors.
- Sample probes.
- Sample ("umbilical") lines.
- Sample pumps.
- Sample conditioning equipment (e.g., heaters, condensers, gas dilution equipment).
- Data loggers or programmable logic controllers (PLCs).
- DAHS that electronically record all measurements and calculate the emissions.

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[3] For SO_2 emissions and heat input only.

[4] For NO_X emissions only.

[5] If the LME qualifying thresholds are met and this method is selected, it must be used for all parameters, i.e., for SO_2, NO_X, and heat input (as applicable).

Table D-3 CEMS Requirements for U.S. Emission Cap and Trading Programs

To measure this essential parameter...	The following CEM systems are required...	To provide data in these units of measure[6]...
SO_2 tons	• SO_2 system • Stack gas flow rate system • Moisture system (in some cases)	ppm scfh % H_2O
NO_X tons	• NO_X system • Stack gas flow rate system • Moisture system (in some cases) or • NO_X-diluent system[7] • Stack gas flow rate system • Moisture system (in some cases)	ppm scfh % H_2O lb./mmBtu scfh % H_2O

The specific components of a CEMS depend upon what parameter is being monitored and the required units of measure. For instance, a typical CEMS used to measure SO_2 or NO_X concentration might consist of a sample probe, umbilical line, sample pump, condenser, SO_2 (or NO_X) analyzer, PLC, and DAHS. Table D-3 summarizes the types of CEMS that are needed to measure the essential parameters (i.e., SO_2 and NO_X tons) in the U.S. cap and trading programs.

D.2.1.2 Alternative SO_2 and Heat Input Monitoring Methodology for Gas- and Oil-Fired Units (Appendix D)

If an affected unit meets the definition of "gas-fired" or "oil-fired" in 40 CFR 72.2, the source may use the alternative methodology in Appendix D of Part 75 instead of CEMS for certain parameters. Appendix D applies only to the measurement of the SO_2 mass emissions rate and the unit heat input rate.

Appendix D requires continuous monitoring of the fuel flow rate and periodic sampling of fuel characteristics, such as sulfur content, gross calorific value (GCV), and density. The measured fuel flow rates are used together with the results of the fuel sampling and analysis to determine the SO_2 mass emissions rate and/or the unit heat input rate, depending on the requirements of the applicable program(s).

> The alternative methodology in Appendix D of Part 75 applies exclusively to gas- and oil-fired units. The SO_2 mass emissions and/or unit heat input are determined using fuel flow meters and the results of periodic fuel sampling and analysis.

D.2.1.3 Alternative NO_X Monitoring Methodology for Oil- and Gas-Fired Peaking Units (Appendix E)

If an affected unit in the Acid Rain Program or NO_X Budget Trading Program meets the definition of a "peaking unit" in 40 CFR 72.2 and also qualifies as "oil-fired" or "gas-fired," then the alternative methodology in Appendix E of Part 75 may be used to monitor the NO_X emissions rate, in lieu of CEMS.

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[6] The acronym "ppm" means parts per million; "scfh" means standard cubic feet per hour; lb. is pounds; and "mmBtu" is million British thermal units, where 1 Btu = 1.06 kilojoules.

[7] This system consists of an NO_X monitor and a diluent gas (CO_2 or O_2) monitor.

The Appendix E methodology for oil- and gas-fired peaking units pertains only to the monitoring of NO_X emissions rate. To use this methodology, a correlation curve of NO_X emissions rate vs. heat input rate is first derived from emissions testing; then, the hourly unit heat input rate is measured using the Appendix D methodology, and the hourly NO_X emissions rate is determined from the correlation curve.

If the Appendix E method is selected for a qualifying unit, the owner or operator must:

- Use the Appendix D methodology to measure the hourly unit heat input rate.
- Perform four-load emissions testing to develop a correlation curve of NO_X emissions rate versus heat input rate.
- Continuously monitor key parameters related to NO_X formation (e.g., excess O_2 for boilers, water-to-fuel ratio for turbines, etc.). Acceptable ranges and values for the parameters must be defined in a QA plan.
- Redetermine the correlation curve once every five years or if any of the monitored parameters are outside the acceptable range of values for greater than 16 consecutive unit operating hours.

D.2.1.4 Alternative Monitoring Methodology for Low Mass Emission Units

If an affected unit qualifies as an LME unit, Part 75 provides an alternative methodology that may be used instead of CEMS. The alternative monitoring methodology for LME units is found in 75.19. The LME methodology does not require actual continuous monitoring of emissions or unit heat input. Rather, hourly SO_2, NO_X, and CO_2 emissions are determined using fuel-specific default emission rates ("emission factors") and estimates of hourly heat input. Once the LME methodology has been selected, it must be used for *all* program parameters, i.e., for SO_2, NO_X, CO_2, and heat input, if the unit is in the Acid Rain Program, and for NO_X and heat input if the unit is in the NO_X Budget Trading Program. "Mixing-and-matching" other Part 75 methodologies with LME is not permitted.

The LME methodology in 40 CFR 75.19 provides an alternative to CEMS for determining SO_2, NO_X, and CO_2 emissions and unit heat input. To qualify to use the LME methodology, a unit must be gas- or oil-fired and its SO_2 and/or NO_X mass emissions must not exceed certain annual or ozone season limits.

In the most basic form of the LME methodology, hourly emissions are estimated by multiplying the maximum rated unit heat input by a "generic" emissions factor provided in the rule. This results in a conservatively high estimate of the unit's emissions. If the source wants to make a more realistic estimate of emissions, heat input can be determined by monitoring fuel flow and conducting fuel sampling for GCV in lieu of using the maximum rated heat input method. Owners and operators of LME units also have the option of performing NO_X emissions rate testing to determine more representative fuel- and unit-specific default NO_X emission rates.

To use the LME methodology for a particular gas-fired or oil-fired unit, the owner or operator must demonstrate that the SO_2 and/or NO_X mass emissions from the unit do not exceed the annual threshold limits shown in Table D-4. For instance, a unit in the NO_X Budget Trading Program must demonstrate that its ozone season NO_X mass emissions do not exceed 50 tons.

D.2.1.5 Monitoring Methods for Industrial Sources

In the U.S. emissions cap and trading programs, EGUs are the predominantly affected units. In some cases, monitoring of industrial sources can be more complex than the monitoring of EGUs.

Under the Ozone Transport Commission (OTC) NO_X Budget Program, there were 43

Table D-4 Low Mass Emission Units

A combustion unit may qualify as a low mass emissions, or LME, unit if it...	
• Meets the definition of a gas-fired or oil-fired unit in 72.2, and	
• If its SO_2 and/or NO_x mass emissions meet the following limits:	
For Acid Rain Program units: • ≤ 25 tons of SO_2 per year and • < 100 tons of NO_x per year	For NO_x Budget Trading Program units: • ≤ 50 tons of NO_x per ozone season and • < 100 tons of NO_x per year[8]

facilities and more than 120 units in the industrial source category. These units encompassed a wide variety of industries, including electric, gas, and sanitary services; petroleum refining; pulp and paper; chemical products; primary metals; and other miscellaneous source categories. The units were primarily industrial boilers and monitored according to Part 75.

In the NO_x Budget Trading Program, certain states have elected to regulate two additional categories of units, i.e., cement kilns and refinery process heaters. These facilities do not produce electrical or steam load, and for the kilns, the formation of CO_2 during the calcination process prevents the heat input rate from being determined in the same manner as it is for boilers, i.e., by using flow rate and diluent gas monitors. To address the unique monitoring issues associated with these sources, EPA revised Part 75 in 2002 to include special provisions for non-load-based units. In addition, the cement industry was given an exemption from heat input monitoring by New York State.[9]

Smelters are an industrial source category that is not currently regulated under either of the U.S. emissions cap and trading programs. For the major smelter units that discharge to the atmosphere through stacks (e.g., dryers, roasters, etc.), Part 75 monitoring potentially could be applied. However, fugitive emissions from smelters are not easily captured or quantified. If smelters were to be considered for inclusion in a cap and trade program, further analysis of the sector, including appropriate monitoring approaches, would need to be conducted.

D.2.1.6 Alternative Monitoring Systems and Petitions

Subpart E of Part 75 provides a mechanism that allows the owner or operator of an affected unit to submit a petition to the Administrator for approval of an alternative monitoring system. To obtain approval, the petition must demonstrate that the alternative system has the same (or better) precision, reliability, accessibility, and timeliness as that provided by a certified Part 75 CEMS. The performance of any proposed alternative system must be demonstrated by simultaneously testing it against a fully certified CEMS or an EPA reference test method. The petition must also include QA provisions and missing data substitution procedures that are consistent with those in Part 75. Partly due to the rigorous requirements of Subpart E and partly because the Appendix D, Appendix E, Appendix G (Determination of CO_2 emissions), and LME-excepted methods in Part 75 provide substantial flexibility in choosing a monitoring methodology, EPA has received and approved only a few Subpart E petitions to use alternative monitoring systems.

Part 75 provides additional regulatory flexibility, whereby the affected unit may petition the EPA Administrator requesting relief (or minor variances) from certain provisions of Part 75. Each petition must explain why the

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[8] This limit applies only if the source is required to (or elects to) report NO_x mass emissions on a year-round basis.

[9] All of the affected cement kilns are in New York State.

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• If its SO_2 and/or NO_x mass emissions meet the following limits:	
For Acid Rain Program units: • ≤ 25 tons of SO_2 per year and • < 100 tons of NO_x per year	For NO_x Budget Trading Program units: • ≤ 50 tons of NO_x per ozone season and • < 100 tons of NO_x per year[♠]

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[♠] This limit applies only if the source is required to (or elects to) report NO_x mass emissions on a year-round basis.

[♥] All of the affected cement kilns are in New York State.

proposed alternative is being suggested in lieu of the regulatory requirement and must contain enough information for the reviewing agency (or agencies) to evaluate the request.

The option to petition is a critical part of the emissions monitoring program. The Part 75 monitoring and reporting requirements are written in a way that ensures applicability to the broadest range of facilities; however, given that there are thousands of affected units using Part 75, not every situation or circumstance can be accounted for in the regulation. The petition process serves as a vehicle through which individual units or facilities can use alternative means to accomplish the principal objective of Part 75, which is to ensure complete and accurate emissions accounting. The regulatory flexibility provided by the petition process reduces the cost of monitoring and reporting emissions for many sources and facilitates program implementation.

> A consistent petition process is critical in a cross-border trading program. Petitions are like case law. Therefore, decisions made by one country should not contradict or compromise previous decisions made by the other nation.

D.2.2 Monitoring System Certification Process

Before any data from Part 75 monitoring systems can be reported as quality-assured, the systems must pass a series of certification tests to demonstrate that they are capable of providing accurate emissions data. The overall monitoring system certification process consists of several steps, as shown in Figure D-2. The process begins by selecting the monitoring methodology to be used for each parameter and then submitting an initial monitoring plan. Next, the monitoring equipment is installed, notices of certification testing are provided, the tests are conducted, and a certification application is submitted to EPA and to the state agency for review. The steps in the certification process are discussed in greater detail in Sections D.2.2.1 through D.2.2.5. Section D.2.2.6 describes recertification and diagnostic testing.

D.2.2.1 Submit Initial Monitoring Plan

The initial monitoring plan identifies the overall monitoring strategy for the affected unit. The plan must contain sufficient information about the monitoring systems to demonstrate that all of the regulated emissions from the unit will be measured and reported. The monitoring plan has both a hard copy and an electronic portion.

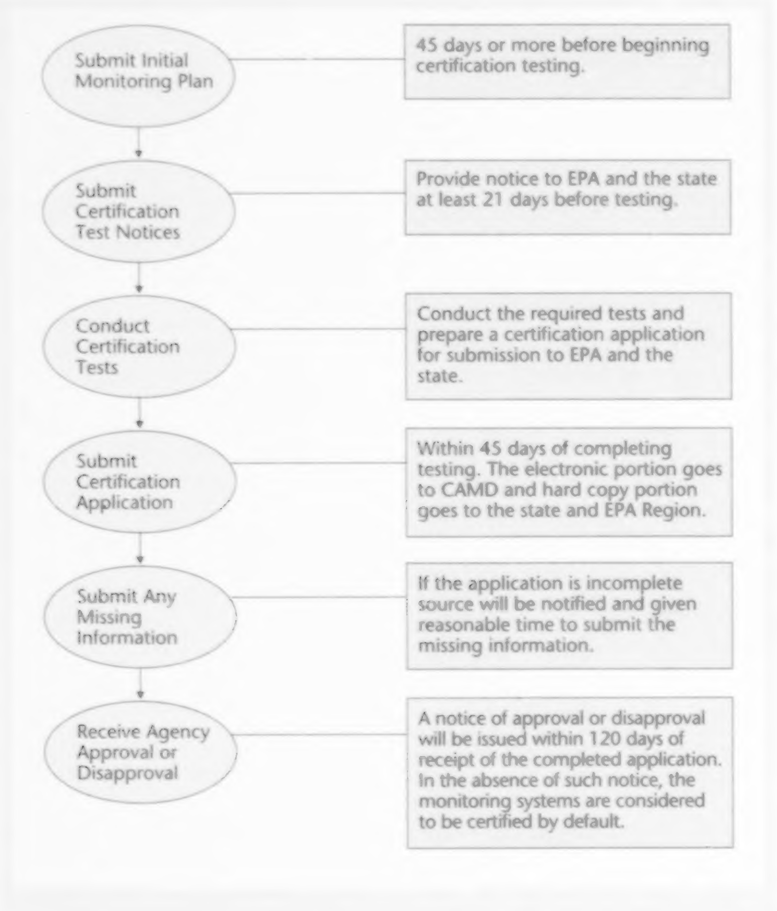
At least 45 days before certification testing begins, the electronic portion of the initial monitoring plan must be submitted to EPA's Clean Air Markets Division (CAMD) in the Agency's standardized EDR format, and the hard copy portion must be submitted to the applicable EPA Regional Office and to the appropriate state or local agency. The electronic portion of the monitoring plan is then reviewed by CAMD, and feedback is sent to the facility, to the EPA Region, and to the state. Any deficiencies or issues identified in the review process are resolved between the facility and the reviewing agencies.

The monitoring plan is to be a "living" document that reflects changes over time in the monitoring systems. As technology advances, new monitors may replace the monitors originally described in the monitoring plan, or the monitoring methodology may change. Also, facility operations may change and necessitate the use of additional monitors or alternative placement of existing monitors. The monitoring plan must be updated to reflect any and all such changes. For example, replacing a gas analyzer requires a monitoring plan update, because the source is required to report the make, model, and serial number of each analyzer.

D.2.2.2 Submit Certification Test Notices

Certification test notices must be sent to CAMD, to the EPA Regional Office, and to the appropriate state or local air agency at least 21 days prior to conducting the required certification testing. There is one exception to this: for the certification

Figure D-2 Monitoring System Certification Process


Submit Initial Monitoring Plan
Submit Certification Test Notices
Conduct Certification Tests
Submit Certification Application
Submit Any Missing Information
Receive Agency Approval or Disapproval

45 days or more before beginning certification testing.

Provide notice to EPA and the state at least 21 days before testing.

Conduct the required tests and prepare a certification application for submission to EPA and the state.

Within 45 days of completing testing. The electronic portion goes to CAMD and hard copy portion goes to the state and EPA Region.

If the application is incomplete source will be notified and given reasonable time to submit the missing information.

A notice of approval or disapproval will be issued within 120 days of receipt of the completed application. In the absence of such notice, the monitoring systems are considered to be certified by default.

of Appendix D fuel flow meters, the notifications are not required.

D.2.2.3 Conduct Certification Tests

The types of certification tests required by Part 75 are summarized in Table D-5.

D.2.2.4 Submit Certification Application

Within 45 days after completing the required certification testing, a certification application must be submitted. There are two parts to the application: electronic and hard copy. The electronic piece of the application consists of a complete, updated monitoring plan and the results of the certification tests, in EDR format. This piece is sent to CAMD. The hard copy piece of the application consists of an application form, the hard copy certification test report, and any changes made to the hard copy portion of the monitoring plan as a result of the testing.

If the certification application is incomplete or is missing any information, the reviewing agencies will notify the source, and a reasonable amount of time will be given to submit the required information.

D.2.2.5 Receive Agency Approval or Disapproval

The permitting authority will issue a notice of approval or disapproval of the certification application within 120 days of receiving the complete application. If this notice is not

Table D-5 Part 75 Certification Tests

This type of certification test...	Is required for...	And its purpose is...
Seven-day calibration error test	Gas and flow monitors	To evaluate the accuracy and stability of a monitor's calibration over an extended period of unit operation.
Linearity check	Gas monitors	To determine whether the response of a gas analyzer is linear across its range.
Relative accuracy test audit (RATA)	Gas and flow monitoring systems (three-load test for flow)	To compare emissions data recorded by a CEMS with data collected concurrently with an EPA reference test method.
Bias test	SO_2, NO_X, and flow monitoring systems	To determine whether a monitoring system is biased low with respect to the reference method, based on the RATA results. If a low bias is found, a bias adjustment factor must be calculated and applied to the subsequent hourly emissions data.
Cycle time test	Gas monitoring systems	To determine whether a CEMS is capable of completing at least one cycle of sampling, analyzing, and data recording every 15 minutes.
Flow meter accuracy test	Appendix D fuel flow meters	To demonstrate that a fuel flow meter can accurately measure the fuel flow rate.
NO_X emissions rate testing and heat input measurement at four unit loads	Appendix E peaking units	To construct a correlation curve of NO_X emissions rate vs. heat input rate.
NO_X emissions rate testing at one or more unit loads	LME units	To determine fuel- and unit-specific NO_X emission factors for reporting purposes.
DAHS verification	Units using CEMS or Appendix E and/or Appendix D monitoring methodologies	To ensure that all emission calcuiations are being performed correctly and that the missing data routines are being applied properly.

given within 120 days, then provided that all required tests were successfully completed, the monitoring systems are considered to be certified by default.

D.2.2.6 Recertification and Diagnostic Testing

Whenever a replacement, modification, or other change is made to a monitoring system that could significantly affect the ability of the system to accurately measure emissions, the system must be recertified. Also, if the flue gas handling system or unit operation is changed and there is a significant change in the unit's flow or emissions concentration profile, the affected monitoring systems must be recertified.

Examples of situations that require recertification of Part 75 monitoring systems include:

- Replacement of an analyzer.
- Replacement of an entire CEMS.
- Change in location or orientation of a sampling probe.
- Fuel flow meter replacement.

The requirements for recertification are basically the same as those shown for initial certification in Figure D-2, except that an initial monitoring plan submittal is not required and the test notification requirements are slightly different. Note also that in some instances, EPA requires less than a full battery of tests for recertification.

Not all changes made to a certified monitoring system require recertification. In many cases, only diagnostic testing is required to ensure that the system continues to provide accurate data. For a more thorough discussion of recertification and diagnostic testing, see section 75.20(b) and Question 13.21 in EPA's "Part 75 Emissions Monitoring Policy Manual."[10]

D.2.3 Quality Assurance and Quality Control Procedures

Following initial certification, all Part 75 monitoring systems are required to undergo periodic QA testing to ensure that the monitoring systems continue to provide accurate data. For CEMS, the QA test requirements are found in either:

- Appendix B of Part 75 and section 75.21, for sources that report emissions data year-round.

  or

- Section 75.74(c), for NO_X Budget Trading Program sources that report emissions data only during the ozone season, from May 1 through September 30.

For Part 75 fuel flow meters, the ongoing QA test requirements are in section 2.1.6 of Appendix D, and for Appendix E NO_X monitoring systems, the QA requirements are found in sections 2.2 and 2.3 of Appendix E.

D.2.3.1 QA Test Requirements for Year-Round Reporters

Year-round reporting of emissions data is required for all Acid Rain Program units and for certain NO_X Budget Trading Program units.[11] The ongoing QA test requirements for year-round reporters are summarized in Table D-6. Table D-6 shows that for CEMS, the routine QA testing is required at three basic frequencies: daily, quarterly, and semi-annual/annual.

Calibration error checks and flow monitor interference checks are required daily; gas monitor linearity checks, flow-to-load ratio tests, and (for differential pressure-type flow monitors) leak checks are required quarterly, and RATAs are required either semiannually or annually, depending on the results of the test.

For Appendix D fuel flow meters, the basic test frequency for the required accuracy tests is annual, and for Appendix E systems, NO_X emissions testing is required once every five years, to develop a new correlation curve.

Note that there are some exceptions to the basic QA test requirements and frequencies shown in Table D-6. For instance, linearity checks are not required for SO_2 or NO_X monitors with span values of 30 ppm or less. For calendar quarters in which the unit operates for less than 168 hours, limited exemptions from linearity checks and limited extensions of RATA deadlines are available. The limits of these exemptions and extensions are as follows: at least one linearity check is required per year, and a RATA is required at least once every eight calendar quarters, regardless of the number of unit operating hours.

EPA recognizes that sometimes circumstances beyond the control of the source owner or operator (e.g., a forced unit outage) prevent a linearity check or RATA from being done in the calendar quarter in which it is due. To provide regulatory relief in these instances, Part 75 allows the test to be done in a "grace" period, immediately following the end of that quarter. For linearity checks, the grace period is 168 unit operating hours, and for RATAs, it is 720 unit operating hours.

D.2.3.2 QA Test Requirements for Ozone Season-Only Reporters

If a unit is in the NO_X Budget Trading Program but is not an Acid Rain Program unit, emissions

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[10] The Policy Manual is located at **http://www.epa.gov/airmarkets/monitoring/polman/index.html**

[11] Certain states allow NO_X Budget Trading Program sources to choose between year-round and ozone season-only reporting.

Table D-6 Ongoing QA Test Requirements for Year-Round Reporters

Perform this type of QA test...	On these continuous monitoring systems...	At this basic frequency...
Calibration error test	Gas and flow monitors	Daily
Interference check	Flow monitors	Daily
Linearity check	Gas monitors	Quarterly
Flow-to-load ratio or gross heat rate test	Flow monitors	Quarterly
Leak check	Differential pressure-type flow monitors	Quarterly
RATA and bias test	Gas and flow monitors (bias test applies to SO_2, NO_X, and flow monitoring systems, only)	Semiannual or annual [12]
Accuracy test	Fuel flow meters	Annual
NO_X emissions rate testing	Appendix E systems	Once every five years

data may be reported on an ozone season-only basis rather than year-round, if this is allowed by the state regulation. If ozone season-only reporting is permitted and this option is selected, the QA procedures under section 75.74(c) in Subpart H of Part 75 must be met. These procedures require some pre-ozone season QA testing between October 1 and April 30 and other QA testing inside the ozone season (May 1 to September 30).

The QA test requirements for ozone season-only reporting are considerably different from, and quite a bit more complex than, the requirements for year-round reporters. In view of this, sources that qualify to use the ozone season-only reporting option must carefully weigh the perceived benefits of this option (e.g., reduced reporting requirements, less required maintenance of CEMS during the off-season) against the potential invalidation of emissions data (and consequent loss of NO_X allowances) that could result from a misunderstanding or misapplication of the rule requirements.

D.2.3.3 QA/QC Program

Part 75 requires all owners and operators of affected units to develop and implement a QA/QC program for the continuous monitoring systems. Each QA/QC program must include a written plan that describes in detail the step-by-step procedures and operations for a number of important activities, such as the routine maintenance procedures for the monitoring systems and the procedures used for required QA tests. Records must also be kept of all testing, adjustment, and repair of the monitoring systems (i.e., maintenance logs). This QA plan must be made available to the regulatory agencies upon request during field audits.

D.2.3.4 Out-of-Control Periods and Missing Data Substitution

In emissions cap and trading programs, it is essential to account for the emissions from a source during each hour of unit operation, because comparing the total mass emissions for the compliance period (i.e., year or ozone season) to the total number of allowances held determines compliance. Therefore, Part 75 requires a complete data record for each affected unit. Emissions data must be reported for each unit operating hour.

In real-life situations, however, quality-assured emissions data may not be available for some hours, because monitoring equipment occasionally malfunctions or needs to undergo routine maintenance, and sometimes a routine QA test is failed. For any unit operating hour in which a monitoring system is unable to provide quality-assured data, the system is considered to be "out of control." Data recorded by an out-of-control monitoring system are unsuitable for Part 75 reporting and may not be used in the emission calculations. For each hour of an out-of-control period, emissions data must be provided in one of the following ways:

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[12] Depending on percent relative accuracy obtained in the previous test, the next RATA is required either semiannually or annually.

- Using an approved Part 75 backup monitoring system that is not out of control.

  or

- Using an EPA reference test method.

  or

- Using an appropriate substitute data value.

Many facilities do not have backup monitoring systems, and even if they do, there is no guarantee that the backup monitor will be "in control" during an outage of the primary monitor. In view of this, there needs to be a standard methodology for determining appropriate substitute data values during missing data periods.

CEMS Missing Data Procedures

In general, the Part 75 missing data procedures for CEMS are designed to provide conservatively high substitute data values, to ensure that emissions are not underestimated during monitor outages. Application of the missing data procedures begins at the date and hour of "provisional certification," i.e., when the CEMS has passed all required certification tests and starts generating quality-assured data. Two distinct sets of missing data algorithms are described in Part 75: the "initial" and the "standard" missing data routines. The initial missing data algorithms in section 75.31 are temporary "spin-up" procedures that are used for a specified period of time, after which the standard missing data algorithms in sections 75.33 through 75.37 begin to be applied. For both the initial and standard missing data procedures, all of the appropriate substitute data values are calculated and applied automatically by the DAHS.

The initial missing data algorithms are simple, and the substitute data values derived from them are likely to be close to the actual source emissions. For example, the algorithm for SO_2 is the arithmetic average of the SO_2 concentrations from the hour before and the hour after the missing data period. For NO_X and flow rate, the substitute data value for each hour is an arithmetic average of the historical data at similar load levels.

The standard missing data routines use a "tiered" approach, which takes into account both the percent monitor data availability [13] (PMA) and the length of the missing data period. When the PMA is high (≥ 95 percent) and the missing data period is relatively short (< 24 hours), the standard missing data algorithms are nearly identical to the initial missing data routines; consequently, the substitute data values are generally not punitive. However, as the PMA decreases and the length of the missing data period increases, the substitute data values become increasingly conservative (i.e., conservatively high), to ensure that emissions are not underreported. If the PMA drops below 80 percent, regardless of the length of the missing data period, the maximum potential concentration or emissions rate must be reported.

The initial and standard missing data algorithms for NO_X and stack gas flow rate are load-based, in order to provide more representative substitute data values. Note, however, that certain units in the NO_X Budget Trading Program do not produce electrical or steam load (e.g., cement kilns). To accommodate these sources, EPA added a series of special missing data algorithms for NO_X and flow rate to Part 75 in 2002. The algorithms are structurally similar to the standard missing data routines, except that they are not load-based. The rule allows the affected sources to define "operational bins" corresponding to different process operating conditions and to populate each bin with CEM data. The substitute data value for each missing data hour is then drawn from the appropriate operational bin.

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[13] In its simplest form, the PMA is the ratio of the number of quality-assured hours to the number of unit operating hours, in a specified look-back period. The PMA is calculated hourly by the DAHS.

Missing Data Procedures for Appendices D and E

Appendix D of Part 75 includes missing data procedures for fuel flow rate, fuel sulfur content, GCV, and density. The Appendix D missing data algorithms are considerably less complex than the CEMS missing data routines. The standard Appendix D missing data algorithms for fuel flow rate are the most sophisticated, in that they are fuel-specific and load-based. However, the substitute data value for each hour is simply an arithmetic average of the data in the corresponding load bin, based on a look back through 720 hours of quality-assured data.

Appendix D also requires missing data substitution for fuel sulfur content, GCV, and density whenever the results of the required periodic sampling and analysis for any of these parameters are missing or invalid. The missing data approach is quite simple: the maximum potential value of the parameter is reported for each hour of the missing data period.

Appendix E missing data substitution is relatively straightforward. When the QA/QC parameters are unavailable or outside the acceptable range of values, the substitute data value is simply the highest NO_X emissions rate from the baseline correlation curve. When the measured heat input rate is above the highest value from the baseline testing, conservatively high NO_X emission rates (and in some cases, the maximum potential NO_X emissions rate (MER)) must be reported. For Appendix E units with add-on NO_X emission controls, whenever the controls either are shut off or cannot be documented to be working properly, the fuel-specific MER must be reported.

D.2.3.5 Conditional Data Validation

When a significant change is made to a CEMS (e.g., replacement of an analyzer) and the system must be recertified, the CEMS must pass a series of recertification tests before it can be used to report quality-assured data. Recertification takes at least seven days (since a seven-day calibration error test is one of the required tests). However, while the recertification tests are in progress, the requirement to report emissions data for every unit operating hour remains in effect. Without regulatory relief, this could result in an extended period of missing data substitution, with a consequent loss of allowance credits.

To alleviate this situation, section 75.20(b)(3) of Part 75 allows "conditional data validation" (CDV) to be used for recertification events. CDV provides sources with a means of minimizing the use of substitute data while a CEMS is being tested for recertification. To take advantage of this rule provision, as soon as the monitoring system is ready to be tested, a calibration error test should be performed. This is called the "probationary calibration." If the probationary calibration is passed, data from the CEMS are assigned a "conditionally valid" status from that point on, pending the results of the recertification tests.

If the required recertification tests are then performed and passed within a certain time frame, with no test failures, all of the conditionally valid data recorded by the CEMS from the date and hour of the probationary calibration to the date and hour of completion of the required tests may be reported as quality-assured. However, if one of the major recertification tests (e.g., a linearity check or RATA) is failed, then all of the conditionally valid data are invalidated and missing data substitution must be used until all of the required tests have been successfully completed.

Part 75 extends the use of CDV beyond recertification events. The procedures may also be used for initial certification, diagnostic testing, and routine QA testing.

D.2.4 Electronic Reporting

In U.S. SO_2 and NO_X emissions cap and trading programs, affected units are required to report electronic data of various kinds (e.g., emissions data, monitoring plan information, results of certification and QA tests, etc.) to EPA at certain times, as specified in Part 75.

D.2.4.1 Initial Reporting

The initial Part 75 electronic reporting requirements include the submittal of a monitoring plan and the results of the monitoring system certification tests. These requirements are discussed in Sections D.2.2.1 and D.2.2.4 above.

D.2.4.2 Quarterly Reporting

For each affected unit, emissions data must be reported quarterly, beginning with either the date and hour at which all certification tests are completed (known as the date of "provisional certification") or the date and hour of the certification deadline specified in the rule, whichever comes first. EPA uses the quarterly report data to assess compliance, by comparing each unit's reported annual SO_2 mass emissions and/or ozone season NO_X mass emissions against the number of allowances held.

The quarterly reporting of hourly emission data (as opposed, for example, to annual reporting) is critical to the success of cap and trade programs. Quarterly reporting eases the administrative burden associated with the data reconciliation and allowance accounting process, because it enables EPA and the affected sources to work together during the year or ozone season to correct any problems with the data, rather than waiting until the year or ozone season is over. By reducing the potential for erroneous emissions data, this process also increases the ability of sources to ensure that they have allowances, as of the allowance-holding deadline, at least equal to their total emissions and reduces the potential for violations.

All quarterly reports must be submitted to EPA by direct computer-to-computer transfer, either by email or by using an EPA-provided software tool known as the Emissions Tracking System File Transfer Protocol, or ETS-FTP. The reports are due within 30 days after the end of each calendar quarter. During this 30-day submission period, the reports may be revised and resubmitted as many times as necessary.

The data in each quarterly report must be in a standardized EDR format provided by EPA.[14] The DAHS must be capable of recording all of the necessary data and putting the data into this format.

The quarterly EDR files must include the following essential information:

- Facility information.
- Hourly and cumulative emissions data.
- Hourly unit operating information (e.g., load, heat input rate, operating time, etc.).
- Monitoring plan information.
- Results of required QA tests (e.g., daily calibrations, linearity checks, RATAs, etc.).
- Certification statements from the designated representative or authorized account representative, attesting to the completeness and accuracy of the data.

The data from each quarterly report submittal are recorded and stored in EPA's ETS. The tracking system consists of the aforementioned submission software (i.e., ETS-FTP) and data checking routines, housed in an EPA mainframe computer. All sources must obtain an account and a password from EPA in order to submit their EDR files. The success of the emissions cap and trading programs depends vitally on ETS. It instills confidence in allowance transactions by certifying the existence and quantity of the commodity (emissions) being traded in the form of allowances.

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[14] The version 2.1 and 2.2 EDR formats and accompanying instructions are found on the CAMD Web site at **http://www.epa.gov/airmarkets/reporting/edr21/index.html**.

Each quarter, EPA reviews and evaluates the EDR reports, using a four-step review process:

- Data review.
- Feedback to sources. EPA provides feedback to the sources, based on the results of the ETS and monitor data checking (MDC) software evaluations. The feedback reports indicate that either:
  - The data have been accepted and will be stored in the EPA mainframe for the purposes of annual reconciliation and dissemination.

  or

  - The EDR is unacceptable and contains "critical errors" that prevent the data from being used for allowance accounting and dissemination.
- Data resubmission. EPA requires reports with critical errors to be resubmitted by a specified deadline (generally within 30 days).
- Data dissemination. All data are reviewed, and preliminary and final emission data reports are prepared for public release and compliance determination.

D.2.5 Audits and Inspections

When emissions data are reported in a standardized electronic format such as the EDR, regulatory agencies can develop software tools with which to audit the data. The results of these electronic audits can serve as a basis for targeting problem sources, either for more comprehensive electronic audits or for field audits. In the Part 75 audit program, both electronic audits and field audits are routinely performed.

D.2.5.1 Part 75 Electronic Audit Program

EPA's CAMD performs routine electronic audits on the Part 75 electronic quarterly reports, using the ETS and MDC software tools. EPA also occasionally performs special (ad hoc) electronic audits to look for other specific data reporting problems (e.g., incorrect application of the missing data routines).

EPA has made the MDC software available to all via the Internet.[15] Also, ETS has a "test" region where quarterly reports can be sent to receive a preliminary feedback report. Thus, the regulated sources can prescreen their EDR data prior to official submittal. This greatly reduces the number of required resubmittals due to critical errors.

D.2.5.2 Audit Targeting

EPA has recently developed an electronic auditing software tool known as the Targeting Tool for Field Audits (TTFA). This tool is intended to be used primarily by state agencies to assist them in targeting sources for field audits. The TTFA tool is capable of identifying a variety of CEMS operation and maintenance problems, such as monitoring systems with an excessive number of failed calibration error tests or linearity checks, sources with long periods of monitor downtime, and monitoring systems with improperly set span and range values.

D.2.5.3 Field Audits

EPA relies primarily on state and local agencies to conduct field audits of Part 75-affected sources. In many instances, the field audits are integrated with routine source inspections. The audits encourage good monitoring practices by raising plant awareness of Part 75 requirements. Field audits generally include the following activities:

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[15] The MDC software and information on how to use it can be found at **http://www.epa.gov/airmarkets/monitoring/mdc/index.html**

- Preparation (e.g., monitoring plan review, examination of historical EDR data using MDC or the TTFA, etc.).
- On-site inspection of the monitoring equipment and system peripherals.
- Records review.
- QA test observations.
- Interviews with the appropriate plant personnel.

EPA has developed a Field Audit Manual, which is available on the Internet.[16] The Field Audit Manual details recommended procedures for conducting field audits of Part 75 CEMS. The manual includes tools that can be used to prepare for an audit, techniques that can be used to conduct the on-site inspections and records review, proper methods for observing QA tests, and guidelines for preparing a final report. Checklists are also provided that can be used to ensure that all necessary data are obtained during the audit. EPA has designed the audit procedures in the manual so that personnel with varying levels of experience can use them.

D.3 ENVIRONMENT CANADA'S PROTOCOL FOR CONTINUOUS EMISSION MONITORING SYSTEMS (REPORT EPS 1/PG/7)

D.3.1 Description

In September 1993, Environment Canada published "Protocols and Performance Specifications for Continuous Monitoring of Gaseous Emissions from Thermal Power Generation," Report EPS 1/PG/7. This document was developed to provide guidance on Environment Canada's expectations for the performance of CEMS for electric power generation units. In 2005, EPS 1/PG/7 has been revised with minor changes and additions to address specific issues raised by stakeholders. This revision does not change the overall context of the report.

EPS 1/PG/7 provides specifications for the design, installation, and operation of automated CEMS used to measure gaseous releases of SO_2 and NO_x from fossil fuel-fired steam electric generating facilities. It presents procedures used to determine the various CEMS parameters during initial certification testing and subsequent long-term operation of the monitoring system.

Additionally, guidelines are provided to assist in the development of a site-specific QA/QC plan, in conjunction with the appropriate regulatory agency. The resulting plan forms an integral part of the overall requirements for the operation of each CEMS.

EPS 1/PG/7 is a technical document that may be used by regulatory agencies for setting requirements to achieve accurate measurement of NO_x and SO_2 emissions via CEMS. It does not set out the policy context for monitoring; nor does it specify where CEMS must be used or how they must be used to support operating permits, emission caps, or emission trading systems. This is left to the appropriate regulatory agency.

D.3.2 Summary of Current Use in Canada

D.3.2.1 Application within the Thermal Power Generation Sector

The requirements specified in EPS 1/PG/7 are recommended guidelines from the federal government. It is left to regulatory agencies to implement them.

EPS 1/PG/7 has been widely used by Canadian provinces in establishing their own CEM requirements. Two of Canada's provinces, Ontario and Alberta, have adopted EPS 1/PG/7 as a basis for their provincial CEM requirements. The Greater Vancouver Regional District, a region within British Columbia, has also adopted EPS 1/PG/7 by reference.

Other jurisdictions do not have explicit requirements for CEMS. In these areas, the issue of monitoring is approached on a case-by-case basis, and any requirements are outlined in a source's operating permit. Often, EPS 1/PG/7 requirements, or sections thereof, are referenced within these approvals.

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[16] The Field Audit Manual is found at **http://www.epa.gov/airmarkets/monitoring/auditmanual/index.html**

D.3.2.2 Application within Other Industrial Sectors

Although it was originally intended for the thermal power generation sector, EPS 1/PG/7, or sections thereof, has been applied to CEMS in industrial sectors. Examples include cement kilns, smelters, pulp and paper units, wood-fired boilers, municipal and biomedical incinerators, and cremators. Typically, EPS 1/PG/7 is referenced in the unit's operating permit.

D.4 ANALYSIS

D.4.1 Differences between Canadian and U.S. Monitoring Requirements (EPS 1/PG/7 and 40 CFR Part 75)

Many of the differences[17] between EPS 1/PG/7 and 40 CFR Part 75 are a result of the context in which the two monitoring tools have been developed. In Canada, EPS 1/PG/7 is a technical document that may be used by regulatory agencies for setting requirements to achieve accurate measurement of NO_x and SO_2 emissions. It does not specify where CEMS must be used or how they must be used to support operating permits, emission caps, or emission trading systems. In the United States, 40 CFR Part 75 was developed specifically for an emissions cap and trading regime. From this wider scope, many additional requirements relating to accountability, transparency, and other aspects necessary for an effective trading regime are encompassed in the regulation. These requirements serve to maintain the credibility of a program where the emissions monitored acquire monetary value as tradable commodities.

Other differences between the two systems are more technical in nature and are simply different methods for meeting similar objectives concerning performance specifications, test procedures, and QA procedures. Some of the key differences between EPS 1/PG/7 and 40 CFR Part 75 are:

- Data acquisition system requirements—These are less detailed in EPS 1/PG/7.
- Bias—EPS 1/PG/7 has specific limits to bias. Bias adjustment factors are allowed for both high and low bias, if the bias is within the specific limits. 40 CFR Part 75 allows high bias, and adjustment factors are required for low bias.
- EDRs—EPS 1/PG/7 does not require EDRs. This is specified in detail in 40 CFR Part 75 and is necessary for compliance determination and QA programs that are based on the submitted EDRs.
- Missing data—Requirements for missing data in 40 CFR Part 75 are more detailed than in EPS 1/PG/7.
- Unit operating data—EPS 1/PG/7 does not have the requirements for submitting fuel usage, fuel GCV, etc., that are specified in 40 CFR Part 75.
- Flow monitors—EPS 1/PG/7 allows the use of heat rate calculations using heat input rate and F-factors or other engineering calculations for determining flow, while 40 CFR Part 75 requires flow monitors, with some exceptions for gas- and oil-fired units.
- Procedural differences—Numerous procedural differences exist between the two systems because of the extensive prescriptive requirements of 40 CFR Part 75. These include:
  - The quarterly submission of monitoring plans and QA performance test data
  - The certification of the data by a corporate designated representative or authorized account representative
  - The QA check of the submitted EDRs by EPA computers.

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[17] Much of the information in Section D.4 was obtained from Jahnke (2001, 2004).

Within an emissions cap and trading regime, the monitoring and reporting requirements provide the basis for guaranteeing the value of the allowances to be traded. While accuracy is essential, of equal importance is consistency in the methods by which the emissions are monitored and reported. Hence, these requirements must be harmonized so that the allowances traded among facilities are considered fungible under a cross-border emissions cap and trading regime.

With 40 CFR Part 75, EPA has already developed requirements to meet the needs of an emissions cap and trading program that are not currently present in Canada. Additionally, the United States has gained experience in trading of emissions and the associated monitoring needs under the Acid Rain Program, which began in 1995. This is true at both the government level and within the electric power generating sector itself.

Should Canada participate in a joint emissions trading program with the United States, Canada should be prepared to implement 40 CFR Part 75.

D.4.2 Impact of Implementing 40 CFR Part 75 in Canada

D.4.2.1 Consistency with EPS 1/PG/7

Despite the differences between 40 CFR Part 75 and EPS 1/PG/7, the directions of the two documents are consistent. EPS 1/PG/7 provides options for meeting its requirements and does not specify any particular type of CEMS. If a cross-border emissions cap and trading system were established, participants would be able to choose appropriate equipment to meet EPS 1/PG/7 in such a way that it would contribute to meeting 40 CFR Part 75 requirements at a later date.

D.4.2.2 Required Upgrades/Changes at Electricity Generating Units

Currently, no Canadian CEMS is equivalent to a U.S. CEMS meeting 40 CFR Part 75. This is not to imply that a Canadian system is necessarily less accurate or precise. However, due to the differences in EPS 1/PG/7 and 40 CFR Part 75 and the absence of a national emissions cap and trading regime in Canada, certain elements have not been included. The following describes some of the upgrades/changes that would be needed if 40 CFR Part 75 were to be implemented at Canadian facilities.

One of the key changes to be made is to require the use of DAHS software to generate EDRs. One option is to purchase commercial Part 75 software. Canadian facilities, however, have a tradition of in-house programming for their CEMS and may develop software on their own. In a cross-border emissions cap and trading regime, the regulator will check all EDRs for proper formatting and internal consistencies, necessitating a clear understanding of the 40 CFR Part 75 requirements if this second option is chosen. In the United States, only three of 2,100 affected sources developed their own software, and they have since replaced it with readily available commercial alternatives.

Most Canadian systems will also need to change their missing data and bias routines and add plant operating inputs to a DAHS for a complete EDR. This will come as part of the package if commercial software is purchased, as described above.

The use of flow monitors is mandatory in the U.S. program, with a few exceptions for gas- and oil-fired units. While some plants in Canada use flow monitors to compute mass emission rates, others use heat input/F-factor calculations and will need to install flow monitors.

Additionally, RATA, calibration, and QA criteria are more extensive in 40 CFR Part 75 than in EPS 1/PG/7. While no additional hardware would be required for Canadian units with flow monitors, further work would be necessary for meeting the more comprehensive performance specifications. A modification of the software may also be necessary for installing algorithms for calculations of the flow-to-load test.

In contrast to the United States, many Canadian EGUs have installed in situ CEMS (both path and point). These systems may not be designed to meet daily calibration checks or quarterly cylinder gas checks with protocol gases according to 40 CFR Part 75. Those with path-type monitors would have difficulty modifying existing equipment to meet these requirements. Those with probe monitors employing a slotted tube could retrofit with a sintered tube, which could accept calibration gases. Sintered probe monitors are installed on some Canadian plants and have been installed in the United States to meet 40 CFR Part 75 requirements.

For units that use CEMS to quantify SO_2 or NO_X mass emissions (e.g., coal-fired units), 40 CFR Part 75 requires the use of stack flow monitors, which measure on a wet basis. However, if the SO_2 or NO_X monitor measures on a dry basis, corrections for stack gas moisture content must be applied when calculating the emissions. Therefore, the source must either continuously monitor the moisture content or use an approved default moisture value. While most gas monitoring systems in Canada measure on a wet basis, some use cool dry extractive technology, which would require moisture corrections to accurately calculate the SO_2 or NO_X mass emissions.

Total NO_X emissions, comprising both nitric oxide (NO) and nitrogen dioxide (NO_2), are required in 40 CFR Part 75. Several units in Canada measure NO only. These facilities may be able to use a correction factor in the DAHS to account for discrepancies between total NO_X and NO or between the CEMS and the chemiluminescence reference test method that is required by the U.S. system. If this is not sufficient, the existing systems can be modified with the addition of an NO_2 channel.

The procedural requirements of 40 CFR Part 75 have resulted in the development of a "monitoring culture" within the United States, which is characterized by greater management control and resource allocation than that found in Canada. By necessity, there is corporate management responsibility and interest in the CEM program and the availability of capital and operating funds to maintain the CEMS in compliance with 40 CFR Part 75. It is likely that this support for the CEM program would develop if Canada were to participate in a cross-border emissions cap and trading program.

D.4.2.3 Perspectives on CEMS in Other Industrial Sectors in Canada

While the electric utility sector and industrial boilers were initially identified as prime candidates for a joint U.S.-Canada emissions trading program, two other sectors—base metals smelting and cement kilns—have also been identified as potential players in Canada. The base metals smelting industry is the largest single contributor to SO_2 emissions in Canada. The cement manufacturing industry is one of Canada's top 10 industrial sectors for the emissions of both NO_X and SO_2, and it is also a sector whose emissions can be easily monitored at the unit level. The implementation of 40 CFR Part 75 in these sectors is briefly presented below.

Cement Plants

In Canada, most cement plants have installed CEMS. These systems are typically extractive systems that can accept calibration gases, although some do have in situ systems installed. Flow monitors may or may not be installed, depending upon the form of the provincial reporting requirements. If 40 CFR Part 75 requirements were to be implemented in the cement sector, DAHS upgrades and possibly the addition of flow monitors would bring them into conformance with 40 CFR Part 75 requirements.

Smelters

In Canada, it is viewed that smelters, in general, have monitors installed for measuring SO_2 emissions, either for process or for environmental monitoring. Flow monitors may or may not be installed, depending on permit reporting requirements. Monitoring of SO_2 emissions from smelter stacks is relatively easy due to the high concentration of the SO_2 emissions. Emissions are typically on the order of thousands of parts per million, which are not difficult to measure using either extractive or in situ systems. Implementing 40 CFR Part 75 at Canadian smelters would include the incorporation of flow monitors (if necessary) and the addition of software that would generate a 40 CFR Part 75 EDR. For higher concentrations, some difficulty might be experienced in obtaining protocol gases in the appropriate concentration range. In some cases, monitoring systems would have to be upgraded to meet the performance specifications of 40 CFR Part 75.

Fugitive emissions from smelters, however, may play a role in overall emissions; this may lead to difficulties in monitoring within an emissions trading system. Further information is required on this issue.

D.5 SUMMARY

Within an emissions trading regime, the monitoring and reporting requirements provide the basis for guaranteeing the value of the allowances to be traded. While accuracy is critical, the method by which the emissions are monitored and reported is also important. These requirements must be harmonized between the United States and Canada so that the allowances traded among facilities are considered fungible under a cross-border emissions cap and trading regime.

Current CEM requirements in the United States for the existing emissions cap and trading programs (Acid Rain Program and the NO_X Budget Trading Program) are contained in 40 CFR Part 75 - Continuous Emission Monitoring. In Canada, the federal government has established guidelines, as distinguished from regulations as in the United States, for CEMS for thermal power plants in EPS 1/PG/7, "Protocols and Performance Specifications for Continuous Monitoring of Gaseous Emissions from Thermal Power Generation."

Many differences between EPS 1/PG/7 and 40 CFR Part 75 are technical in nature, relating to the methods for determining accuracy. Other differences are a result of the context in which the two monitoring tools have been developed. EPS 1/PG/7 lacks specific requirements for electronic data reporting and verification, whereas in 40 CFR Part 75, these have been developed and are widely utilized by U.S. government and industry.

With 40 CFR Part 75, EPA has established requirements to meet the needs of an emissions trading program not currently present in Canada. Additionally, the United States has gained experience in monitoring and trading of emissions under the Acid Rain Program, which began in 1995. This is true at both government and state levels and within the electric power generating sector itself. In order to have equivalency of allowances traded among U.S. and Canadian facilities, there would need to be a high level of consistency between the systems in the two countries with respect to accuracy, accountability, transparency, predictability, and flexibility.

Also, the number of units in the existing U.S. cap and trading programs that have already installed CEMS to meet the U.S. requirements significantly outnumber the potential units in Canada that would be included in a cross-border emissions cap and trading program. Therefore, if a cross-border emissions cap and trading system were established, then 40 CFR Part 75 requirements would need to be implemented in Canada.

The implementation of emission and monitoring requirements at Canadian facilities comparable to those in the United States is technically feasible. Any Canadian facility following EPS 1/PG/7 should not need to replace an entire CEMS, but need only upgrade or add on to its existing system, in order to be 40 CFR Part 75 compliant. This may involve additional hardware, software, and QA/QC procedures to conform to operation and maintenance requirements of the emission monitoring provisions.

D.6 REFERENCES

Jahnke, J.A. (2001). "Continuous Emission Monitoring Issues for Cross-Border Emissions Trading – Final Report." Ref: STA:ENVC:2904R, December 14, 2001. Report to Environment Canada.

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SECTION E

ALLOWANCES USE

Allowances are the tradable units of an emissions cap and trading program. Each allowance, issued by a governing agency, is an authorization to emit a specific quantity of a particular pollutant. In other words, an allowance is required for emitting a certain quantity of a regulated gas (e.g., nitrogen oxides (NO_X), sulfur dioxide (SO_2)) from regulated activities. By the end of each true-up, or reconciliation, period that follows the compliance period, participating sources must submit (or the government must deduct) the appropriate number of allowances to compensate for their emissions during the compliance period.

Allowances are a commodity with an economic value. Because allowances are tradable, this value is revealed through the market. In turn, the allowance price provides useful information for regulated entities when developing their compliance strategies. Emitters are able to compare their abatement costs with the expected allowance price to assess the most cost-effective way to meet the compliance requirements.

To simplify program design and operation, reduce transaction costs, and increase the economic effectiveness of a program, allowances should be fungible—that is, each allowance should be interchangeable with other allowances in the program. Simplicity is enhanced by avoiding the creation of different categories of allowances with different attributes.

This section describes allowances and their use in a cross-border emissions cap and trading program context, including areas of jurisdictional flexibility such as allowance allocation methodologies. Allowance serialization, allowance distribution and timing, banking, and other aspects of allowance use are discussed. This section also presents anecdotal experience with allowances in the existing U.S. emissions cap and trading programs.

E.1 UNIT OF MEASUREMENT

An allowance is defined by the amount of emissions it allows. In the U.S. Acid Rain Program, for instance, one allowance is currently equivalent to one ton of SO_2. In a cross-border trading system, using a common unit of measure would offer a simpler solution than having two heterogeneous "goods" to trade that generate two prices: one for the U.S. allowances and one for the Canadian allowances. Using a different unit of measurement to define allowances would also make the compliance process more complex, necessitating the use of conversion factors to compare the number of allowances submitted for compliance with the actual level of emissions.

E.2 ALLOWANCE SERIALIZATION

Allowances may be serialized (i.e., assigned a single and unique number or code) to facilitate tracking from creation to compliance use. There are a number of benefits to identifying allowances by serial number. The use of serial numbers facilitates record-keeping so that allowance holders can track the different costs incurred in acquiring allowances. (This may be useful for tax purposes.) Tracking provides additional transparency and protection against accounting discrepancies. Finally, the inclusion of serial numbers in the allowance tracking system (ATS) provides the opportunity to analyze trading patterns and the movement of allowances over time. This may be useful for assessing the impacts of the trading program. At a minimum, allowances must be identified by vintage (i.e., the compliance period for which they are issued) to determine when the allowances are authorized for compliance use.

E.3 ALLOWANCE DISTRIBUTION

The distribution of allowances can be one of the most politically contentious issues when designing an emissions cap and trading program. Distribution decisions have economic, equity, and political consequences. Because an emissions cap and trading program creates new assets with economic value, participants who receive the allowances at no cost through an allocation capture the economic gains from these assets. Under an auction, the auctioning agency (e.g., the government or jurisdiction) captures the value of the assets.

The first decision in the allowance allocation process is which method will be used for distribution. Allowances can be distributed through an auction or directed allocation, or some combination of the two systems. To date, most U.S. emissions cap and trading programs have used directed allocations to distribute the majority of allowances. Some programs have a supplemental auction of allowances to ensure liquidity and to facilitate the entrance of new regulated entities into the system. Experience with the U.S. Acid Rain Program has shown that establishing an auction to ensure liquidity was not necessary, because the allowance markets are working well.

The distribution of the allowances has, generally speaking, little impact on the cost-effectiveness or environmental integrity of the emissions trading program. As a result, in a cross-border emissions cap and trading program, the method by which allowances are distributed does not need to be the same in Canada and the United States. As long as the cap is respected, the method of distributing allowances could be shared with state and provincial governments.

However, since distribution has an impact on the burden sharing of the total cost of abatement, it is a key design element of the trading system. Distribution is particularly important because it impacts the perception of the system's equity as a whole and thus its political acceptability. There is not a single definition of equity. Some may find a directed allocation inconsistent with the "polluter pays" principle. Others may find it inappropriate to require emitters to pay for any emissions plus abatement costs when the environmental goal is to reduce rather than eliminate emissions.

Whatever distribution method is selected, some allowances from within the cap may be set aside. The set-aside allowances (see Section E.9) can be used to allocate allowances to new sources or to create incentives or compensation for certain types of behavior (e.g., early reductions, energy efficiency measures, or renewable energy generation).

E.3.1 Auctions

Auctions are one method for distributing allowances. Under this approach, participating sources are required to bid for the number of allowances they would like to purchase. Generally, the highest bidders receive the allowances at their specified price or at the clearing price. Allowance auctions provide numerous benefits including the internalization of the environmental cost of air emissions upfront by industry. Among the benefits are: 1) auctions create a source of revenue that can be used to offset administrative expenses or be distributed to affected groups; 2) auctions enable the governing authority to collect "windfall" profits that might otherwise accrue to participating sources under a directed allocation approach; 3) auctions avoid some politically contentious issues regarding allocation methodologies (although auctions may involve other politically contentious issues, such as how to use auction proceeds); 4) the winning bids provide the market with a price signal that helps participating sources create a cost-saving, environmentally effective compliance strategy; and 5) auctions provide equal opportunities for new emission sources.

Auctions may be used to distribute only a portion of allowances, with the remainder distributed by a directed allocation method. Some analysts have proposed beginning with a directed allocation system and eventually transitioning to an auction-based system. This would increasingly internalize costs over time and may decrease political opposition from emission sources worried about the cost of allowances.

E.3.2 Directed Allocations

Despite the advantages of actions, the three major U.S. trading systems all rely on directed allocations.

There are at least two important factors to consider when designing a directed allocation approach: baselines and benchmarks. The baseline is the year or years of historical (or predicted) data that are used to calculate the allowance allocation. An important distinction among baseline approaches is whether the baseline is permanent or changes over time. A "permanent baseline" results in a fixed allowance allocation in perpetuity, although it may provide for changes that are specified in advance, such as a fixed reduction each year. The alternative is an "updating baseline" in which the allocation changes over time based on the activities of the participating sources (e.g., increased production as a proportion of total production levels). A permanent baseline, therefore, establishes a fixed distribution of allowances, whereas an updating baseline allows for the redistribution of allowances.

Permanent and updating baselines differ in the incentives they create. A permanent baseline generally has no impact on the decisions of the participating sources once the system is implemented. In theory, an updating baseline influences the decisions made by the operators of participating sources. Because an updating baseline periodically changes the allocation, some sources may have an incentive to do more of the activity that will earn them additional allowances. This effect, however, will be influenced by the demand for the product, cost of the activity, and value of allowances.

Benchmarks, or metrics, are the type of data that are used to calculate the allowance allocation. Different benchmarks include historical fuel or heat input, output, or emissions. Each benchmark produces different "winners" and "losers."

A directed allocation could be based on any of the benchmark measures. The allocation could be based on different benchmarks for different levels if the allocation is a multistage process (e.g., the national authority allocates to state/provincial authorities, which then allocate to the sources).

E.3.2.1 Inputs

Fuel or heat input is one benchmark approach. To calculate the allocations, fuel usage or energy input data are multiplied by an emissions performance metric (e.g., emissions per unit of fuel input). When a single performance metric is used for all sources, an input benchmark rewards participating sources that are inherently cleaner (e.g., natural gas units), have installed emission reduction controls, or pursued early reductions, because those sources' emission rates may be below the performance metric. This approach can work well if the emission sources have a variety of outputs or cross several industrial sectors (e.g., electric generating units, cement kilns, and pulp and paper facilities).

E.3.2.2 Outputs

Output is another benchmark approach. To calculate the allocations, production data are multiplied by an emissions performance metric (e.g., emissions per unit of electricity produced). When a single performance metric is used for all sources, an output benchmark rewards participating sources that are inherently cleaner, operate efficiently, install emission reduction controls, or pursue early reductions. This approach can work well if the sources and/or industries produce a homogeneous product (e.g., electricity). If the product is heterogeneous, the allocating authority must convert the products to a uniform unit or apply different emission performance metrics for each product.

E.3.2.3 Emissions

Emissions are the final benchmark approach. Allocations are calculated based on a participating source's relative share of total emissions. This approach rewards the highest emitting and least efficient sources. It also penalizes participating sources that pursue early emission reductions, install pollution controls, or operate efficiently, because their emissions are lower. When combined with an updating baseline approach, an emissions benchmark weakens incentives for emission reductions.

E.3.2.4 Other Considerations

Several other issues must be addressed if a directed allocation approach is used. These include the following:

- **Baseline Period**: The baseline period for allocations could be historic, current, or even projected. The relative importance of the baseline period increases with the length of the allocation. Allocations using historical baseline periods are attractive to large sources that typically operate near capacity or had an important share of the benchmark, because they are guaranteed a relatively large proportion of the allocated allowances.
- **Updating Frequency**: If an updating baseline approach is used, the length of the interval between allocations may affect the level of influence that updating has on future behavior. For example, if updating is done annually based on output, in theory, it could provide a strong incentive to increase output in order to receive additional allowances. If, however, the time period is longer (e.g., 10 years), the effect will be considerably less. Permanent allocations, on the other hand, provide no such incentive, because changes in behavior will not affect future allocations.
- **Length of Allocation**: Allowances may be allocated to emission sources in advance of the allowances' vintage period (i.e., the period in which the allowances can be used for compliance). Having allowances allocated in advance can add liquidity to the market, because sources and other market participants can trade allowances on the spot market for use in future years. This also helps emission sources develop and implement compliance strategies in advance of the compliance period (e.g., a source that installs an emission control device can sell future excess allowances to generate revenue to help offset the cost of the control).
- **Preserving the Cap**: After a baseline and benchmark are applied, the resulting total allocations should be compared with the intended cap. If too many or too few allowances were created while calculating allocations, a ratchet (i.e., a formula that adjusts each allocation proportionately) can be applied. The resulting total allocation will then match the number of allowances in the cap. This ensures that the cap is not inflated through the allocation process.
- **Incorporating New Sources**: New entrants to the program must obtain allowances to participate in the program. In some allocation schemes with updating baselines, new emission sources may receive allowances. In the case of permanent allocations, new sources may need to obtain allowances from the market. Alternatively, a set-aside could be created for new entrants. The set-aside could hold a specific percentage of the overall cap to cover growth in new sources.

Many analysts have noted that both economic theory and empirical experience suggest that there is not a competitive barrier to new entrants that do not receive directed allowance allocations in emissions cap and trading programs. They argue that emission sources receiving directed allowance allocations have the same marginal "opportunity cost" for every ton emitted as the marginal cost paid by the new entrant. In support of this argument, there is no evidence of entry problems for new electric power plants under the U.S. SO_2 Acid Rain Program, which requires new power plants to purchase all their needed allowances on the market. There has been significant entry by new units, even coal-fired units that do not receive a directed allowance allocation.

E.4 ALLOCATION TIMING

In order to provide affected sources with the certainty necessary to develop a compliance strategy, the rules for the allocation of allowances must be completed and known by the operators of the affected sources prior to the beginning of the compliance period, preferably several years in advance.

E.5 BANKING

Allowances are usually allocated for use in a specific compliance period. The vintage of the allowance identifies the period in which it is eligible to be used. If allowances are unused, they may expire (i.e., be invalidated) or be banked (i.e., carried forward) for compliance use in future periods. Banking avoids allowance price instability and increased use of allowances (and thus increased emissions) around the end of the compliance period. Providing participating sources the ability to bank allowances creates additional flexibility, encourages early reductions, may reduce compliance costs, and, therefore, may increase economic and political support for the program.

The biggest environmental gains from banking come from early reductions. If a participating source reduces emissions more than is required in the early years of the program, the source can bank its surplus allowances for use in the future. This can, however, delay the achievement of an overall environmental goal if banked allowances are used. Because banking does not delay achievement of cumulative reductions, this tradeoff does not represent an environmental concern for problems such as acid deposition, where the environmental problem is caused by total accumulation of a pollutant in the atmosphere. If the relationship between emissions and environmental damage is linear, the environmental benefits of reducing emissions early to bank allowances should offset the environmental costs of using these banked allowances. In such a case, banking would be environmentally neutral at worst.

Banking (or the use of banked allowances) could also be limited when the relationship between emissions and environmental damage is not linear. This is to avoid important environmental damage if emissions peak significantly over the normal level due to the use of too many banked allowances. For problems such as ground-level ozone, where there is concern over short-term episodes of high emissions, the benefits of banking must be weighed against the potential effects.

However, the U.S. experience has shown that limits on banked allowance use often complicate or hinder the operation of emissions cap and trading programs and fail to provide apparent benefits.

E.6 BORROWING

Borrowing would be the use, during a current period, of allowances to be allocated in a future period. Because borrowing could easily jeopardize the credibility of the trading system, borrowing has never been allowed in U.S. systems.

E.7 PROPERTY RIGHTS

An important consideration in the design of emission trading programs is whether emission allowances are defined as property rights for allowance holders. If an allowance is defined as a property right, it could limit the government's ability to adjust the cap or make necessary program changes at a later date. An emission allowance should remain analogous to any other type of authorization granted by government, such as a license to broadcast or to fish. In this way, the regulator retains the ability to modify or revoke allowances and avoids claims by the regulated industry that allowances cannot be taken from it without compensation or that it has a right to future allocations. Existing cap and trade programs expressly prohibit any property rights in their emission allowances. For example, the U.S. SO_2 allowance trading program (section 403(f) of Title IV of the Clean Air Act) states:

> *(f) Nature of Allowances. – An allowance allocated under this title is a limited authorization to emit sulfur dioxide in accordance with the provisions of this title. Such allowance does not constitute a property right. Nothing in this title or in any other provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.*

The government can limit or terminate authorizations to emit. In this way, the government retains the ability to amend, revoke, or reallocate emission allowances. The ability to reallocate allowances is essential if the government wishes to lower the cap on total emissions at a future date. However, in exercising the authority to limit or terminate authorizations to emit, it is important to take account of the potential effect on sources' willingness to rely on the allowance trading system in making compliance and investment decisions. For example, when replacing existing authorizations by new authorizations, it may be desirable to provide some credit to sources holding existing authorizations.

E.8 TRANSPARENCY

By providing data and information in a transparent manner, cap and trade programs can build public confidence by revealing how well the program is enforced and ensuring accountability for each unit of emissions. Transparency can also increase the efficiency of the market and reduce transaction costs by enabling participants to identify potential buyers and sellers. True transparency, however, requires providing the information in a useful and informative format.

Full transparency with public access to information, such as the number of allowances allocated to affected entities and the number of allowances in each account, is a key component to maintain the environmental integrity of the emissions cap and trading system. Full transparency could also reinforce incentives for good environmental behavior because of public awareness of the use of allowances. In the United States, price information is not provided by the U.S. Environmental Protection Agency (EPA) (except in auctions). Not only has provision of such information by EPA not been necessary, but given the wide variation in the circumstances of allowance transactions (e.g., transactions involving future delivery or transactions coupling allowances with other commodities such as fuel), such price data are likely to be confusing and of little use (see Section F.4.2 for further discussion on price).

E.9 SET-ASIDES

Another tool that can be used in allowance distribution is an allowance set-aside. Under a set-aside, a certain number of allowances within the cap are withheld for a specific purpose. The set-aside can be defined as a fixed number of allowances or as a percentage of the total allowance budget.

The set-aside allowances can be distributed for a variety of purposes, including incentives for certain technologies, for energy efficiency or renewable energy programs, as a way to address equity issues, or as a reserve for new entrants to the program.

It is important to also consider how surplus allowances from the set-aside will be managed if they are not distributed. Options include retiring the allowances, saving them for future use, and distributing them to sources through an allocation or auction. Retiring decreases the quantity of allowable emissions (i.e., the cap) and may therefore increase compliance costs for sources. Saving for the future may provide flexibility but reduces the number of available allowances in current years and can also lead to increased compliance costs for current emission sources. Distributing through an allocation or auction is perhaps the most common and economically efficient approach.

The set-aside allowances must come from within the cap so that new allowances do not inflate the cap and undermine the ability to achieve the environmental goal. If a set-aside is used, the basis for awarding allowances from the set-aside and the size of the set-aside allowance pool should be established in advance.

As for the method of allowance distribution, how set-aside allowances are dealt with in Canada and the United States need not be the same, as long as the set-aside allowances respect the total cap (i.e., the set-aside allowances come from within the cap).

E.10 ALLOWANCE ACCOUNTING

Compliance with an emissions cap and trading program is determined by comparing total emissions and allowance holdings. It is therefore critical to ensure the highest level of accuracy in both emissions and allowance data. Tracking each allowance from creation to surrender is an essential step in ensuring accurate allowance information.

Allowance accounting involves developing procedures and information management systems for the creation, transfer, compliance use, and surrender of allowances. The procedures must establish the roles and responsibilities of each party involved in the transaction (the buyer, seller, and administrative agency), the information that is collected to process the transaction, the time required to process the transaction, and the manner in which a transaction is confirmed.

E.11 TAX CONSEQUENCES

When market participants buy allowances, they incur costs. When they sell allowances, they earn revenues. If participants generate profits or losses on their allowance sales, those earnings might incur tax liabilities. In addition, the use of purchased allowances (i.e., allowances with an associated cost to acquire) for compliance purposes may have tax consequences, as the cost of the allowances may be considered an environmental compliance cost.

E.12 THE U.S. EXPERIENCE WITH ALLOWANCE USE

In the U.S. SO_2 allowance trading program, allowances are defined in the Clean Air Act Amendments of 1990 as an authorization to emit one ton of SO_2. The Act also specifies that allowances are not property rights; rather, they are treated as a revocable authorization to emit. Over time, if new scientific information emerges or societal preferences change, allowances can be revoked or discounted to achieve a lower cap level. In the U.S. NO_X Budget Trading Program, banked allowances may be discounted to limit episodic ozone events that could occur if sources used too many banked allowances. Table E-1 presents an overview of allowance use in the SO_2 and NO_X emissions cap and trading programs.

E.12.1 Allowance Serialization

Each allowance in the U.S. SO_2 and NO_X emissions cap and trading programs has a unique serial number. The number includes the vintage year (i.e., the first year that the allowance can be used for compliance purposes) and a unique eight-digit number.

The use of serial numbers aids market participants by making it easier to track the cost basis of each allowance. This is helpful for tax purposes. Serial numbers aid EPA and the public by offering opportunities to analyze allowance use, trading patterns, and program effectiveness.

E.12.2 Allowance Banking

The U.S. SO_2 emissions cap and trading program permits banking with no restrictions. This has had positive effects on environmental quality and has reduced compliance costs. Although banking

Table E-1 Overview of Allowance Use in U.S. SO_2 and NO_X Programs

	U.S. SO_2 Acid Rain Program	U.S. NO_X Budget Trading Program
Definition	Authorization to emit. Not a property right.	Authorization to emit. Not a property right.
Serialization	Yes – vintage + unique number. Allowances are stored in blocks.	Yes – vintage + unique number. Allowances are stored in blocks.
Banking	Unlimited.	Banked allowances are discounted if total bank exceeds 10 percent of initial allocation.
Distribution – auction	2.8 percent of cap auctioned each year.	None.
Distribution – allocation	Benchmark: Heat input multiplied by 1.2 pounds (lbs.) of SO_2 per million British thermal units (mmBtu).[1] Baseline: Average of 1985–1987 (permanent).	Allocation approaches are determined by states.
Tax consequences	Profits (and losses) from allowance trades are subject to capital gains taxes. Purchased allowances used for compliance are considered an environmental compliance cost and have associated tax consequences.	Profits (and losses) from allowance trades are subject to capital gains taxes. Purchased allowances used for compliance are considered an environmental compliance cost and have associated tax consequences.
New sources	Purchase from market.	Determined by states.
Set-asides	Limited number for conservation and renewable energy projects before 1995 (phasing out).	Determined by states.
Government oversight	Market oversight is limited.	Market oversight is limited.

is unlimited in the SO_2 program, regardless of the number of allowances a participating source holds, it is never entitled to exceed the source-specific limits set in the facility's operating permit or other applicable provisions to protect public health.

Under the U.S. NO_X Budget Trading Program, participating sources can bank unused allowances. However, if the total number of banked allowances is greater than 10 percent of the cap, the banked allowances are discounted. This is called progressive flow control. The discount ratio is determined on a regional basis and applied to allowances when they are used for compliance. The ratio is calculated by multiplying the cap by 10 percent and dividing the result by the number of banked allowances. The ratio indicates the number of allowances that can be used at full value, while the remaining allowances are discounted by 50 percent (i.e., two allowances are required for each ton of NO_X emissions). For example, if the cap is 500,000 allowances and 75,000 allowances are banked, progressive flow control would be triggered, since the bank is greater than 10 percent of the cap. The ratio would be 0.67 ((500,000 × 10%) / 75,000). Under this example, 67 percent of a source's banked allowances could be used at full value, while the remaining 33 percent would be discounted, so that two allowances are required for each ton of NO_X emissions.

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[1] One Btu = 1.06 kilojoules.

E.12.3 Allowance Distribution

EPA distributes the majority of allowances for the SO_2 emissions cap and trading program directly to participating sources through a directed allocation. EPA also holds an annual allowance auction where 2.8 percent of the total allowances are sold to interested parties. For the NO_X Budget Trading Program, allowances under the regional cap are distributed to the states, which then allocate their state budgets among their affected sources. A state may leave some allowances in reserve for special state set-aside programs, such as energy efficiency projects.

E.12.3.1 Allocations

The benchmark for the SO_2 allowance allocations is heat input. Heat input was selected because the data were available and this benchmark does not penalize sources that took early action to reduce emissions. The baseline was heat input data from 1985 through 1987. The average of the three years is used, because a single year may not accurately reflect normal conditions at a particular source. For example, a unit may have been offline for maintenance or the weather may have been extreme, increasing demand for heat and/or electricity.

Allocations were calculated by multiplying each participating source's average heat input for 1985 through 1987 by a performance rate of 1.2 lbs. SO_2/mmBtu or, if it was already lower than 1.2 lbs. SO_2/mmBtu, the source's actual emission performance rate.

There were also numerous special provisions to recognize special circumstances and to address equity concerns raised by some states. For example, in some cases, states that had already reduced the emissions of their electric utilities well below the national average were given extra allowances. Similarly, a state with high population growth in the 1980s was given bonus allowances for its electric utilities to compensate for this growth. In all cases, these redistributions were performed without increasing the size of the emissions cap. The Clean Air Act stated that if the allocation calculations resulted in an allocation greater than the available allowances under the cap, each source's allocation would be reduced by the same percentage to maintain the cap. Hence, the increase in allowances allocated to certain participating sources was offset by a decrease in the number of allowances allocated to other sources.

The SO_2 allowance allocations are issued to sources in perpetuity. If a source is shut down or ceases operation, the owner(s) of the source may choose to transfer all future allocations to another source, but EPA does not revoke the allocation. This was done to discourage owners from operating older, inefficient units just to have the allowances.

At the beginning of the program, EPA issued 30 years of allowances to each participating source. At the beginning of each year, EPA issues allowances for a year 30 years in advance. For example, in 2005, EPA will issue allowances with a 2034 vintage. Issuing allowances far into the future provides affected sources and market participants with certainty about allowance availability,[2] but it can complicate future changes to the level of the emissions cap, since allowances have already been distributed well into the future.

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[2] Certainty is not absolute, however, because the United States may discount distributed allowances in the future.

E.12.3.2 SO_2 Auction

Each spring, EPA holds an allowance auction to sell 2.8 percent of total allowances for the year. These allowances are withheld, or set aside, from sources during the initial allocations, and approximately half are auctioned seven years prior to the vintage year of the allowance (the advance market) and half are auctioned during the vintage year of the allowance (the spot market). In other words, the 2005 auction included allowances with a vintage year of 2005 and allowances with a vintage year of 2012. Allowances cannot be used prior to their vintage year.

The auction is a sealed bid process. Interested parties submit a bid for a specific number of allowances and a particular price. The bids are ranked by bid price, and the top bid is fulfilled at the bid price. If allowances remain, the next bid is fulfilled at the bid price. The process continues until there are no allowances remaining or the bids are exhausted. The proceeds from the auction and any unsold allowances are distributed to the sources on a pro rata basis (i.e., proceeds are distributed to the sources from which the allowances were initially withheld).

The Clean Air Act allows EPA to designate a third party to administer the auction.

EPA does not hold an annual auction for the NO_X Budget Trading Program. This trading program is a state program, and while some states have chosen to auction off some allowances to sources (Virginia, Kentucky), most maintain the directed allocation approach.

E.12.4 Allowance Accounting

EPA has established a computerized tracking system to manage all allowance transactions. The data system (see Section F) manages the creation, transfer, and compliance use of allowances. Each participating source has a compliance account in the system. In addition, any person can open a general account in ATS so that he or she can participate in the allowance trading program.

When EPA allocates allowances, the blocks of allowances are transferred into the respective sources' compliance accounts. The allowances reside in the account until the source officially transfers the allowances to another account, general or compliance, or submits the allowances for compliance purposes (i.e., retires the allowances).

Only official transfers—transfers that are submitted to EPA—are entered into the tracking system. Transfers of allowances that will be used for compliance must be recorded in the tracking system, while other transfers (e.g., purchases, sales) are not required to be submitted to EPA.

To submit a transfer, the designated representative (or, for general accounts, the authorized account representative) for the source transferring the allowances uses the Clean Air Markets Division Business System to do online transfers or submits a paper form. EPA added an online allowance transfer option in late 2001, allowing those who wish to transfer allowances to do so over the Internet, either by submitting a file containing the transfer information or by entering the data on the screen. This online capability lowers transaction costs even further and allows the market participants more control over their transactions.

If a paper form is submitted, EPA records the transfer in the tracking system, usually within one or two business days (although the regulations allow five days), and sends a confirmation notice to both transferring and recipient account representatives. When using the EPA Business System, recordation is "real time," with instant confirmation. In addition, each day EPA updates its Web site with that day's transactions.

The information that EPA collects for processing a transaction includes the transferring account ID, account representative, recipient account ID, and allowance serial numbers. EPA does not collect price information, because prices do not provide information necessary to determine compliance with the program. In addition, the price paid may not be an accurate reflection of market prices. Price information without adequate explanation of the underlying transactions could lead to confusion about the market price of allowances.

E.12.5 Allowance Market

The allowance market for the U.S. SO_2 emissions cap and trading program is very active and liquid—over 20 million allowances are traded each year since Phase II began. The financial community has played an important part in the development of the market and has helped sources develop hedging strategies (e.g., options and futures). This has helped sources better manage allowance price risk.

There are numerous participants in the market, including brokers, traders, speculators, source representatives, and individuals. In fact, anyone can participate in the market. As an example, every year, school children in different parts of the United States raise money to purchase one or more allowances at the EPA auction that can be withheld from the pool of available allowances, thereby reducing the level of allowable pollution. This access to the market has not had any effect on prices or allowance availability, but it does provide a useful hands-on lesson about emissions trading.

E.12.6 Tax Consequences

Most allowances are provided to sources through a directed allocation. Since there is no cost associated with these allowances, there are no tax consequences when they are used for compliance. However, if a source uses purchased allowances for compliance, the cost of the allowances is considered a cost of environmental compliance and can be included on the firm's operation costs for tax purposes. For this reason, many sources specify the allowances they want to retire for compliance. If a company sells allowances for a profit (or loss), the earnings from that sale are taxed as capital gains.

The tax consequences of allowances were not determined in the Clean Air Act or by EPA. Rather, the U.S. Internal Revenue Service provided a ruling on these tax consequences.

E.13 SUMMARY

Allowances should be fungible—that is, each allowance should be interchangeable with other allowances. This simplifies program design and operation, reduces transaction costs, and increases the economic effectiveness of the emissions cap and trading program. Simplicity is enhanced by avoiding the creation of different categories of allowances with different attributes.

Emissions and allowances should be measured in the same units (e.g., one ton of SO_2) in order to simplify record-keeping, improve transparency, and create an efficient market for allowances between the two programs. Allowances should be equal to the same unit of emissions in both countries.

To obtain a well-functioning emissions trading system, it is necessary to harmonize a number of design elements with regards to allowances in both countries:

- Serialization of the allowances must follow the same rules and patterns, including the same approach to vintage.
- Banking and borrowing rules must be the same.
- Property rights must be compatible.
- The degree of transparency must be high.
- Rules to create and transfer allowances must be the same.

In addition, the timing for the distribution of allowances (i.e., the number of years in advance that allowances are allocated) and other accounting processes must be the same.

Finally, other aspects of allowance treatment can be different. For example, the provisions for distributing the allowances and the approach to defining and managing set-asides (a number of allowances reserved to create specific incentives) can be different among jurisdictions participating in an emissions cap and trading program, as long as the provisions of the set-aside ensure the integrity of the cap (i.e., allowances set aside come from within the cap). In addition, the methods for distributing allowances and managing set-asides may need to be evaluated from the standpoint of equity and economic impacts on industry in the two different countries.

SECTION F

ELECTRONIC EMISSIONS TRADING REGISTRY: DATA SYSTEMS FOR TRACKING ALLOWANCES AND EMISSIONS

An essential element of emissions cap and trading programs is comprehensive, accurate, transparent, and timely information about emissions and tradable allowances. An electronic emissions trading registry can greatly enhance the collection, verification, management, and dissemination of data for an emissions cap and trading program.

This section discusses principles for designing an electronic registry (Section F.1), the components of the registry (Section F.2), and centralization (Section F.3). It also presents U.S. and Canadian experiences with data tracking systems (Sections F.4 and F.5), as well as the levels of consistency and compatibility that are necessary for electronic registries in a cross-border emissions cap and trading program.

F.1 PRINCIPLES FOR DESIGNING AN ELECTRONIC REGISTRY

The advantages of using electronic registries go well beyond their ability to handle large amounts of data. Using a flexible, comprehensive system to collect and manage data can provide numerous benefits, including:

- Increased data accuracy—Tools such as electronic reporting and automated data quality checks reduce errors and eliminate redundant data entry.
- Reduced time and costs—Electronic reporting and automated data quality checks also reduce the time and costs required to complete, process, and review paper forms. In addition, the electronic storage of data can significantly reduce, or even eliminate, the costs associated with the collection, transport, storage, and distribution of paper forms.
- Enhanced access—Electronic data storage makes it easier and faster to retrieve, analyze, and evaluate relevant data on demand. Improved access to data can also promote confidence in the trading program by permitting program participants and interested members of the public to retrieve data to ascertain compliance, evaluate a program's effectiveness, and make informed decisions.
- Improved consistency and comparability—Electronic reporting and electronic data storage encourage consistency by requiring all program participants to report the same information in a common reporting format. This consistency promotes comparability across time and among program participants.
- An electronic registry should integrate several design principles, described below.

F.1.1 Stress Data Quality

Compliance with an emissions cap and trading program is determined by comparing total emissions and allowance holdings. It is therefore important to ensure the highest level of accuracy in both emissions and allowance data. The registry system should conduct automated data quality checks on every emissions submission. Errors and discrepancies can then be reported to the participating sources.

F.1.2 Promote Transparency

Registries play a critical role in building public acceptance. By providing data in a transparent manner, registries can build public confidence in a program by revealing how well the program is enforced and ensuring accountability for each unit of emissions. Data transparency can also increase the efficiency of the market and reduce transaction costs by enabling participants to identify potential buyers and sellers. True transparency, however, requires providing the information in a useful and informative format.

F.1.3 Design for the Future

When designing registry systems, every effort should be made to create a flexible, adaptable design that can accommodate future program changes as well as new programs. For example, if an emissions cap and trading program focuses on a single pollutant or sector, the system should be designed so that it can accept additional pollutants and sectors in the future. Designing a flexible system initially requires more financial resources and effort, but will reduce administrative burden and reengineering costs in the long run.

Most regulatory agencies already collect some data about the environmental performance of sources. The design of the registry should account for those existing and any planned systems to reduce data redundancy and administrative effort.

F.1.4 Automate Recurring Procedures

Many processes contain repetitive procedures. To the extent that these are automated, they will reduce the effort required to process data.

F.1.5 Emphasize Security

Registries must have a high degree of integrity to prevent fraudulent transactions and malicious attacks on the system. Integrity of data is critical for accurately determining compliance and because allowances in an emissions cap and trading program have economic value. In addition, the costs of compliance and noncompliance are based on emissions data and allowance holdings.

F.2 COMPONENTS OF THE REGISTRY

A fully functioning registry must have several components to collect and manage information about sources, market participants, emissions, allowances, and compliance. The primary components of the registry are the emissions tracking system (ETS) and allowance tracking system (ATS).

The most convenient basis for handling data for an emissions trading program is an electronic registry. The U.S. Environmental Protection Agency (EPA) has developed software especially designed to manage information on emissions trading. The software includes the possibility of linking multiple trading zones. EPA has offered to share this software with other governments, free of charge.

F.2.1 Key Functions of the ETS

The ETS stores the actual emissions reported by the regulated entities. Emissions data stored in the ETS are used by the ATS to verify, during end-of-year reconciliation, that each regulated entity has covered its emissions with an equivalent number of allowances submitted for compliance.

The ETS is based on a detailed regulation that specifies requirements such as the nature of the information to be recorded, the format of the information, and the frequency of the mandatory reporting.

Sources use EPA-provided software to submit their electronic data reports (EDRs) directly to the ETS. ETS performs extensive checks on the EDRs for quality assurance (QA), stores the data on EPA's mainframe computer, and provides the source with a feedback report that includes notification of any errors and an explanation of how best to resolve the errors.

F.2.2 Key Functions of the ATS

F.2.2.1 Ownership Record

The ATS is a compliance system. The key function of the ATS is to determine compliance by tracking the allowances in the system. Each participant [1] has an account in which a list of allowances that he or she owns is kept. When a block of allowances is transferred to another participant, the ATS moves them to the new owner's account. If multiple registries are involved in a program (e.g., a block of allowances is traded between two sovereign states with independent registries), transfers may need to be verified against a "clearinghouse" to enhance the integrity of the system. [2] The clearinghouse could contain a summary of information necessary to verify that the trade is valid.

F.2.2.2 Deduction of Allowances for Compliance

The ATS is used to make allowances available for compliance. At the end of a grace period following the compliance period, the government deducts the number of allowances that corresponds to the participant's emissions covered by the system (see Section G.1) by moving the allowances into a permanent EPA retirement account. Allowances may also be surrendered as a penalty for noncompliance or to enhance the environmental benefits of the program. Once deducted or surrendered, the allowances are no longer transferable, bankable, or usable. Allowances are never deleted from the data system, so any allowance ever issued may be tracked. This allows the system to remain auditable and transparent.

F.2.2.3 Authorized Participants

The ATS should include information on one or more authorized representatives for each allowance account. This information identifies those individuals who are authorized to conduct transactions or other activities on behalf of the account holder. It can also facilitate information flow between the registry operator and the account holder.

In a well-functioning emissions cap and trading system, the conditions to open an allowance account should not be too restrictive to allow the participation of market facilitators such as brokers. Moreover, these conditions must be the same on both sides of the border.

F.3 CENTRALIZATION

When more than one legal or political jurisdiction is included in an emissions cap and trading program, questions relating to registry operation may arise. The jurisdictions may work together to operate a single, centralized registry in which all information is maintained. Alternatively, each jurisdiction may operate an independent registry to maintain information relevant to its program, but share information, when appropriate, with the other registry or registries. There are benefits and drawbacks to each approach.

A centralized registry provides a single point of contact for submitting or querying data, regardless of jurisdiction. Program participants or the public can easily access information from any program with greater ease, thereby improving transparency. Centralization also reduces the need for communication between registry systems and thus reduces the security and data integrity risks associated with open communication. Also, perhaps most importantly, centralization reduces the resource requirements to develop and operate independent data systems for each jurisdiction. The primary drawback of centralization is legal jurisdiction. With a centralized approach, one jurisdiction, or a third party, must manage the data and determine compliance for sources in other jurisdictions.

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[1] As specified in Section F.2.2.3, "Authorized Participants," a participant could be a nonregulated entity.

[2] We assume that a typical registry automatically keeps a record of each allowance transfer. In other words, a transaction log is integrated into a typical ATS.

A decentralized approach overcomes legal jurisdiction issues, but requires greater resources for registry operation and maintenance. In addition, it requires coordination among jurisdictions to establish data requirements and communication protocols.

A decentralized approach would also require a mechanism such as a "clearinghouse" to ensure that any transactions involving more than one registry are valid. Using a centralized approach, the verification function is internal; in a decentralized approach, it is important that an independent verification system is used to ensure that each transaction—including allocations, trades, transfers, and compliance deductions—is allowed within the appropriate emissions cap and trading program(s), and that the account holders and allowances involved are valid.

A balanced option may be to link the two national registries. In this way, legal challenges associated with compliance enforcement due to an international registry would be avoided and the number of windows for reporting and links between registries would be kept low.

F.4 THE U.S. EXPERIENCE WITH DATA TRACKING SYSTEMS

EPA has operated registries for a decade and has learned many valuable lessons. The first-generation registries were expensive and sometimes burdensome. However, as technologies improved and experience increased, EPA reengineered the systems to provide better data collection, auditing, management, analysis, and dissemination capabilities. Today's systems offer unprecedented automation and data access.

As the volume of data has grown, EPA has increased the use of electronic data transfer. In 2004, 100 percent of emissions data and 93 percent of allowance transfers, accounting for 94 percent of all allowances transferred, were submitted electronically. EPA has also introduced an online management system to encourage program participants to use the Internet to manage their participation in the emissions cap and trading program. EPA's registry system is a key component in the transition to a paperless interaction between industry and regulator. In addition, EPA provides sources with reporting software that conducts data quality checks, to use before submitting data. By moving the QA checks to the data source, there is less opportunity for poor quality data to enter the registry.

F.4.1 Emissions Tracking

EPA's registry includes an ETS to collect, audit, and manage emissions data from the more than 3,000 affected units in the U.S. sulfur dioxide (SO_2) and nitrogen oxide (NO_X) emissions cap and trading programs (see Table F-1). Each of the units is required to submit hourly emissions data on a quarterly basis. To simplify and improve the process, EPA provides each source with software to process, format, pre-audit, and submit the data. As the submissions are received, they are processed and audited by the ETS. The ETS reviews the data for errors or omissions, conducting several hundred calculations on each submission. When the audit is complete, the ETS sends an electronic report to the source that details results of the audit and indicates whether the data were accepted or rejected (see Figure F-1).

F.4.2 Allowance Tracking

The ATS is the accounting system for the SO_2 and NO_X allowance trading programs in the United States. The ATS tracks account information, account holdings, and allowance transactions. Account holders can access their accounts to transfer allowances through an online system. The system allows users to register trades and select the specific allowances to transfer. In addition, account holders can

Table F-1 **Required Emissions Data on a Quarterly Basis**

Facility Information
Pollutant Gas Concentrations
Diluent Gas Concentrations
Moisture Data
Volumetric Flow
Daily Quality Assurance Data and Results
Reference Method Backup QA Data
Unit Operating and Cumulative Emission Data
SO_2 Mass Emission Data
NO_x Emission Data
CO_2 Mass Emission Data
Qualifying Low Mass Emission Unit Data
Monitoring Plan Information
Certification Test Data and Results

Figure F-1 **Sample Feedback Quarterly Report Receipt and Status Code Information**

Report received for ORISPL:	000099
Facility Name:	Tamarasc Power
Unit/Stack/Pipe ID:	6B
Status Code for this report:	9
Submission Year:	2003
Submission Quarter:	4
Date:	01/06/2004
Time:	9:48
Submitter User ID:	TMA
Submission Account:	ETSP (ETSP=Official, ETSD=Test)
Receipt ID:	115008
STATUS CODE 9:	Quarterly Report Contains Informational Errors

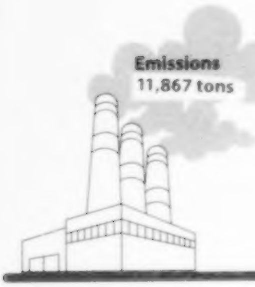
Explanation:

While the EPA has accepted your report, informational errors are present in the report. The following items accompany this letter: A Cumulative Data Summary Table of Emission Values, an Error Report containing detailed descriptions, and a File Summary that lists the number and type of records found in the quarterly data report.

Required Action:

Please investigate the informational errors described in the accompanying feedback and identify any suspect data periods or unusual operations (e.g., startup, shutdown, or operational problems) in the quarterly report. Review and, if possible, correct the identified errors to ensure there is no measurement or reporting problem.

Figure F-2 Allowance Reconciliation



Allowances	
Beginning of year	15,812
Net Allowance (Bought and Sold)	-3,201
Total Allowance Available for Compliance	12,611
Deductions for Emissions	-11,867
Allowances Remaining (Source in Compliance)	744

update information about their account (e.g., adding designated representatives and authorized agents; editing facility data). After an account holder registers an allowance transaction or updates his or her account, the system sends an email confirmation to the relevant parties. The use of these online tools has made participating in the SO$_2$ and NO$_X$ allowance trading programs a paperless process.

Submitting an allowance transfer requires information about the transferring account, authorized representative of the transferring account, receiving account, and specific allowances to be transferred. EPA does not collect information about price, because it is not relevant to enforcing the program or achieving the environmental goal. In addition, price data may not provide useful information, because some transactions have nonmonetary terms (e.g., fuel suppliers may bundle allowances with their fuel; a company with multiple sources may transfer allowances among their accounts), while others may involve more complicated financial or nonfinancial instruments (e.g., futures, options, swaps). Price information is readily available from most brokers, most of whom post price information on their Web sites.

F.4.3 Reconciliation

At the end of each year, after a short grace period, the emissions and allowance data are reconciled. Currently, for the SO$_2$ program, the registry deducts one allowance for each ton of SO$_2$ emissions (see Figure F-2). For the NO$_X$ program, if banked allowances are used, the registry discounts the allowances as necessary before deducting the appropriate number of allowances (see Section E.12.2 for a discussion of discounting banked NO$_X$ allowances).

F.4.4 Public Reporting

As discussed in Section F.1.2, providing public access to source-level emissions and allowance data promotes confidence in the program and provides an additional level of scrutiny to verify enforcement and encourage compliance. In the United States, emissions data are not considered confidential. The Clean Air Act explicitly states that emissions data are public information.

Advances in technology and the Internet have made it possible to provide interested persons with timely and useful information about emissions, allowances, and program results. EPA's registry provides data access tools through the Internet that allow people to develop customized queries for the data that are of most interest to them. In addition, mapping and other applications provide data in an easy-to-understand graphical format.

F.5 THE CANADIAN EXPERIENCE WITH DATA TRACKING SYSTEMS

F.5.1 Canadian Ozone-Depleting Substances Trading

Environment Canada operates systems similar to the ETS and ATS described above under the Canadian Environmental Protection Act, 1999 (CEPA) for two ozone-depleting substances: hydrochlorofluorocarbons (HCFCs) and methyl bromide. The administrator of the system communicates by mail the exact number of allowances for the coming year to each recipient a few weeks prior to the beginning of the year. On an ongoing basis, transferors and transferees provide information on the transfers of allowances by faxing (or mailing) a form, available on a Web site,[3] to the administrator of the program. Each transfer has to be approved by the Minister or its administrator before being valid. Only the quantity of the transfer has to be divulged; the value of the transfer is not released. The administrator keeps up to date a database on each account using relational database software (i.e., MS Access). Although Ministerial approval of allowance transfers is required for specified substances under the Ozone-Depleting Substances Regulations, 1998, CEPA does not require Ministerial approval of allowance transfers within a system of tradable units (s. 326).

Unlike the NO_X and SO_2 systems in the United States, the ozone-depleting substances trading system does not control emissions per se, but rather controls the apparent consumption (i.e., production plus import minus export) of ozone-depleting substances. Authorized importers and producers produce an annual report on apparent consumption and submit it to the authority for compliance assessment.

F.5.2 Ontario Emissions Trading

With its Ontario Emissions Trading Code, Ontario developed a registry that fulfills the basic functions of an ATS and an ETS, since it notifies the public of the distribution and retirement of nitric oxide (NO) and SO_2 emission allowances and the creation and retirement of NO and SO_2 Emission Reduction Credits.[4] The Ontario Registry's Allowances Tracking System is not based on serialization of allowances (see Section E) to track their initial ownership; instead, each transfer has to specify the initial owner name.

F.6 SUMMARY

In assessing the qualities of well-functioning tracking systems for both emissions and allowances, this section identified a number of desirable elements. These elements could be brought together in electronic registries that would provide data accuracy, reduce time and costs, enhance data access, and improve consistency and comparability.

Emissions and allowance tracking systems provide the link between the electronic data reporting requirements and the determination of compliance with the emissions cap and trading program. Being crucial elements of compliance determination, the type of data, the data requirements, and the accuracy and quality of the data in both Canada and the United States must be the same. This is because of the need for consistency and comparability, protection of allowance values, and to ensure equity.

In order to gain public acceptance, trust, and understanding of the results of an emissions cap and trading program, full and open disclosure of relevant public and private decisions needs to be consistent in Canada and the United States. This transparency is a critical element of emissions cap and trading programs and includes the establishment of rules and regulations and determining if an emissions source is in compliance. Accurate and timely information is important to a credible, well-functioning emissions cap and trading program.

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[3] See **http://www.ec.gc.ca/ozone**.

[4] Ontario Ministry of the Environment, "Ontario Emissions Trading Code," Toronto, Ontario, January **(http://www.ene.gov.on.ca/envision/env_reg/er/documents/2003/XA03E0001.pdf)**.

Tools are available that integrate all the data and functionality of a registry into a single, flexible software system. This system is adaptable to new programs and the inclusion of additional sectors and is capable of communicating with other registries and emissions reporting systems. Using these tools would allow Canada and the United States to have comparable and consistent national emissions and allowance tracking registries necessary for a cross-border emissions cap and trading program.

SECTION G

COMPLIANCE AND ENFORCEMENT

This section addresses the key questions of compliance and enforcement considerations for a cross-border emissions cap and trading program. Section G.1 presents an overview of compliance in relationship to a cap and trading program and describes compliance determination in more detail. Section G.2 discusses enforcement. Sections G.3 and G.4 present U.S. and Canadian experience with compliance and enforcement.

G.1 OVERVIEW OF COMPLIANCE

Determining compliance in an emissions cap and trading program is relatively simple and straightforward. The regulator simply compares a source's total emissions to the permissible emissions, based on the allowances held in the source's account. Some important decisions, however, must be made prior to implementing an emissions cap and trading program. These decisions involve measurement and quantification of emissions, allowance banking rules, emission reporting deadlines, and the deadline for holding allowances for compliance.

At the end of each compliance period, the emission sources should be given enough time to verify and submit the emissions data. This verification period should not be so short as to cause the emission sources to submit data that have not been properly quality assured, but not so long as to unreasonably delay compliance assessment. It should also allow enough time for the regulating authority, once it receives the data, to finish conducting the compliance determination prior to the end of the subsequent compliance period, when the process will begin again. At the end of each compliance period and during the time when sources are assuring the quality of their emissions data, the rules should provide for a short grace period so that sources can make final allowance trades. This allows sources to ensure that their account contains allowances equal to or greater than their emissions. This can be accomplished by specifying in advance an allowance transfer deadline—the final date for sources to trade allowances for use in the compliance year.

G.1.1 Compliance Determination

The first step in compliance determination is to determine the total amount of emissions during the compliance period. A cap and trading program has several elements that are critical to that first step in compliance determination. One element is emissions monitoring, which must meet stringent technical requirements to ensure that emissions are properly measured for each regulated activity. Another element is emissions data reporting, which must conform to certain protocols to ensure that the information is forwarded to the authority in an accurate and timely way. In addition, there are verification systems to ensure quality of the emissions monitoring and reporting and to indicate any necessary corrections. The requirements for these elements are specified in the cap and trading program regulations and include, for example, operating, quality assurance and quality control, and documentation requirements (see Section D on monitoring and reporting). The regulator may audit and inspect a facility's emissions monitoring and reporting to ensure compliance with the requirements. If the facility is not in compliance with these requirements, then substitute emissions data must be used for the period of noncompliance, in lieu of reported data, and the facility may be determined to be in violation of the program regulations.

The second step is to compare the amount of regulated emissions with the amount of allowances held for compliance in the compliance period for each regulated entity. A cap and trading program has an allowance trading system to ensure that allowance allocations, transfers, and holdings are properly tracked and that emissions and allowances are correctly compared.

In a cross-border emissions cap and trading program, the definition of "compliance" must be the same in both countries with regard to allowance holding requirements, as well as with regard to emissions monitoring and reporting requirements.

G.1.2 Regulated Entity

A regulated entity could be equipment (e.g., a boiler), a production unit (e.g., a power plant), or a legal entity that owns or operates the production unit (e.g., a power generator firm). This must be determined and defined by the program's applicability criteria. The number of regulated entities would be much larger if they are defined as equipment rather than plants, or as plants rather than firms. However, the identity of the legal entity that owns or operates a plant can change during a compliance period or before an allowance transfer deadline, and ownership structures can be very complex (e.g., with multiple owners and the use of partially or wholly owned subsidiaries or affiliates or limited liability corporations). Further, foreign owners may be involved. Consequently, making the owner or operator the regulated entity may make the determination of compliance difficult.

G.1.3 Compliance Date

There are two significant dates related to compliance determination: one is the deadline for reporting emissions; and one is the deadline for transferring and holding allowances to equal the reported emissions for the compliance period. For instance, the last date to report emissions data could be 30 days after the end of the year. Then, firms might have an additional 30 days to make trades and hold allowances for compliance.

G.1.4 True-Up Process

The true-up process, also known as reconciliation, is the process through which reported emissions are compared with allowances held. During the true-up period, the accounts in the allowance tracking system are frozen, in that transfer of allowances that could be used for compliance is suspended until compliance is determined.

G.2 ENFORCEMENT

G.2.1 Penalties for Noncompliance

A stringent, automatic penalty for noncompliance is an integral feature of a well-functioning emissions cap and trading program. This penalty should be applied automatically in cases where a source does not hold sufficient allowances by a designated date to cover mass emissions during the compliance period. In addition to the automatic penalty, discretionary civil or criminal penalties may be applied in cases of emissions in excess of allowances held. In cases where there is noncompliance with other requirements of the cap and trade program (e.g., emissions monitoring, reporting, and other requirements), discretionary civil or criminal penalties may also be applied. Discretionary penalties should be determined based on the nature and severity of the violation. The penalties should be great enough to provide the appropriate incentives for compliance and can take the form of allowance surrender, fines, or criminal penalties.

G.2.1.1 Noncompliance with the Cap

In cases where a source does not have sufficient allowances to cover its emissions, the automatic penalty should also be accompanied by an allowance recovery (or offset) of one-to-one to maintain the environmental integrity of the program. Under a one-to-one offset, one allowance from the next compliance period would be deducted for the source for every unit of excess emissions in the current compliance period.

However, a one-to-one restoration rate without other accompanying punitive measures for noncompliance could imply that a source could, in effect, use allowances from future compliance periods to attain an emissions reduction target. This could result in a scenario where the emissions cap is always exceeded. Hence, it is very important that penalties deter noncompliance.

In addition to the one-to-one offset to maintain environmental integrity, the automatic penalty should include either further allowance deductions or a financial penalty for each unit of excess emissions. With an allowance deduction penalty (i.e., where a source would have to turn in an amount of allowances that is a multiple, greater than one-to-one, of its excess emissions), the aggregate cap of emissions in the next compliance period is reduced. The environmental benefits of the program would increase due to the allowances deducted as a penalty.

If the automatic penalty is a financial penalty (in addition to the one-to-one offset), the penalty should be set significantly higher than the expected marginal abatement cost—the expected market price of allowances—to create an effective deterrent for noncompliance, but not too high so as to be unreasonable (e.g., in cases where excess emissions resulted from inadvertent error). (If higher penalties are warranted, in some circumstances the automatic penalty could be supplemented by discretionary penalties.) Further, since it may be difficult to project the future marginal abatement cost and that cost may change, it may be appropriate to set the level of the automatic financial penalty in accordance with some benchmark such as a recent auction or market index.

G.2.1.2 Other Penalties

The regulator should have the discretion to impose civil or criminal penalties on sources or individuals who violate requirements of the cap and trading program. Civil and criminal penalties provide direct incentives for the legally responsible individuals at the affected source to behave responsibly. Owners, operators, or designated representatives should be required to certify that each form submitted to the regulating authority for the source (e.g., allowance transfers, emission reports) is true, accurate, and complete. The certification should also acknowledge potential civil or criminal penalties under the law for acts and omissions within the scope of their responsibilities under the emissions cap and trading program.

Discretionary civil or criminal penalties need not be the same in each country.

G.3 THE U.S. EXPERIENCE WITH COMPLIANCE AND ENFORCEMENT

G.3.1 Compliance

Under the Acid Rain Program (Title IV of the Clean Air Act), affected units submit their continuously monitored emissions data quarterly to EPA. EPA then verifies the quality, completeness, and consistency of the reported data, the adherence to the Electronic Data Report (EDR) format, and the appropriate use of missing data procedures, if applicable.

For circumstances in which a source measures emissions from several regulated units through a single stack—a "common stack"—the designated representative (DR) has the option of using the Common Stack Allowance Deduction Form to identify the percentage of allowances to be deducted from each unit to cover all of the stack's emissions. If the DR does not specify particular unit accounts, then EPA will take an equal percentage of allowances from each unit emitting through the stack. However, EPA recently amended its regulation to provide for emissions and allowances to be compared on a plant level, rather than a unit level, starting in 2006. With compliance at the plant level, it will no longer be necessary to divide emissions among regulated units at a common stack.

Once all the emissions data are checked and all valid and timely allowance transfers are implemented, allowances are deducted to cover emissions and are transferred into a permanent

EPA emissions retirement account. Any remaining allowances of the current compliance year vintage are valid for compliance deductions in any future year. After reconciliation is complete, EPA sends each DR a report entitled "Allowance Deductions for Compliance Year 20YY" detailing the unit's allowance deductions.

The schedule for the U.S. Acid Rain Program compliance process is as follows:

- April 30, July 30, October 30, and January 30 – Deadline to submit 1st, 2nd, 3rd, and 4th quarter emission reports, respectively.
- December 31 – Compliance year ends.
- January 30 – Deadline to submit 4th quarter emission reports.
- March 1 (February 29 in a leap year) – Allowance Transfer Deadline (no allowance transfers permitted for compliance in the previous compliance year after this date).

The schedule for the U.S. NO_X Budget Trading Program compliance process is:

- July 30 and October 30 – Deadline to submit 2nd and 3rd quarter ozone season emission reports.
- September 30 – Compliance period (ozone season) ends.
- November 30 – Allowance Transfer Deadline (no allowance transfers permitted for compliance in the previous compliance period after this date).

G.3.2 Enforcement

There are several layers of enforcement measures in the Acid Rain Program in the United States:

- Under the offset provision, violating sources must offset excess SO_2 emissions with allowances from the next year in an amount equivalent to the excess. A source may have allowances deducted either immediately or, if the unit shows immediate deduction would interfere with electric reliability, at a later date. If the unit plans to have allowances deducted at a later date, the company (that is, the designated representative) must submit to EPA an Excess Emissions Offset Plan, which must undergo public review and comment before approval. This offset plan states when the unit will provide the necessary allowances for compliance. (Since the commencement of the Acid Rain program, all offset allowances have been immediately deducted.)
- The owners or operators must also pay an automatic penalty of $2,963 per excess ton of emissions in the year 2004. (The 1990 penalty of $2,000 is adjusted each year for inflation.)

The excess emission penalties for the Acid Rain Program are automatic. In other words, while the determination of the amount of excess emissions is subject to legal challenge, there is no negotiation of or legal challenge to the penalty amount once the determination of the excess emissions amount is final.

EPA also has discretion to seek civil or criminal penalties for excess emissions and other violations, including failure to install and certify monitors on time or to report emissions. EPA can seek financial penalties up to $25,000 per day for violations and, in the case of willful violations, seek criminal penalties.

For the NO_X Budget Trading Program, a regional, ozone season-only trading program, the automatic penalty is entirely in the form of allowance deductions. Violating sources must offset each excess ton of NO_X emissions with one allowance and are penalized two additional allowances, for a total of three allowances from the next year, for each ton of excess emissions during the compliance period. There are discretionary civil and criminal penalties for violations of the NO_X Budget Trading Program, as is the case with the violation of any requirements of the Acid Rain Program or any provision of the Clean Air Act.

G.4 COMPLIANCE AND ENFORCEMENT IN CANADA

Although Canada does not have any existing national emissions cap and trading programs for NO_X or SO_2, the Canadian Environmental Protection Act, 1999 (CEPA) contains provisions outlined below that provide for the compliance and enforcement elements of such a regime.

Section 326 of CEPA grants regulation-making authority with respect to a system of tradable units, when used in conjunction with the regulation of toxic substances under sections 93 or 167. Section 326 specifies that the system may contain elements such as:

- The methods and procedures for conducting sampling, analyses, tests, measurements, or monitoring under the system.
- The conditions related to the creation, distribution, exchange, sale, use, variation or cancellation of a tradable unit.
- The conditions for participation in the system, including environmental and temporal limits.
- Reports and forms related to the system.

The authority to require monitoring and reporting is also found in sections 93 and 167, respecting toxic substances and international air pollution. By way of example, existing regulations under CEPA contain reporting requirements to the Minister of the Environment regarding the emission or manufacture of specified substances or regarding the proper functioning of pollution control equipment. [1]

These general provisions would allow harmonization of a Canadian and American trading program with respect to compliance elements such as reporting deadlines, length of compliance periods, true-up requirements, and allowance offsets.

Provincial governments also have authority for compliance and enforcement in air quality management programs. Were cross-border trading to be implemented, dependent on the specific design of select elements, the provinces could play a key role in the compliance and enforcement provisions of the program. This could involve ensuring that facilities covered in the emissions cap and trade program are in compliance with the monitoring, reporting, and verification requirements.

As well, Part 10 of CEPA provides the authority to the federal government for enforcement of noncompliance with the monitoring, reporting and verification requirements of a cross-border cap and trade program, which are similar to the civil and criminal penalties under the Clean Air Act. The Minister of the Environment may designate law enforcement officials of provincial governments to enforce provisions of CEPA. Such designation would take place pursuant to a federal-provincial administrative agreement.

G.5 SUMMARY

Compliance and enforcement are key aspects of cap and trading programs. This would also be the case for a Canada-U.S. cross-border emissions cap and trading program.

Under a cross-border regime, Canadian regulatees will be subject to Canadian law and U.S. regulatees will be subject to U.S. law. Regardless, based on U.S. experience, what is considered to be in compliance or out of compliance needs to be the same in both countries. For compliance with the allowance-holding requirement, the penalties for noncompliance, be they allowances or financial penalties, need to be automatic and equivalent in both Canada and the United States.

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[1] For example, see: Asbestos Mines and Mills Release Regulations, SOR/90-341; Chlor-Alkali Mercury Release Regulations, SOR/90-130; Ozone-Depleting Substances Regulations, 1998, SOR/99-7.

The harmonization of compliance schedules as regards compliance dates and the true-up process is necessary. Different schedules and the absence of harmonization could make operation of the program problematic and could adversely affect the market and create undesirable trading behavior.

Discretionary civil or criminal penalties need not be the same in Canada and the United States, but they would need to be stringent enough to ensure compliance.

SECTION H

ANALYTICAL TOOL DEVELOPMENT AND FEASIBILITY ANALYSIS

In order to assess the impacts of cross-border emissions cap and trading between Canada and the United States, joint analytical tools were developed and expanded. The Integrated Planning Model (IPM) was used to prepare illustrative modeling scenarios with emission reductions of SO_2 and NO_X from the power sector in both countries. Further, since the air quality implications of lowering emissions and allowing trading are important to estimate, air quality modeling was also performed. Air quality models used emission data from the power sector to assess the broad air quality and environmental benefits that could result from emission reductions in both countries.

Over the past two years, joint analytical tools were developed to evaluate the environmental and economic impacts of a potential cross-border emissions cap and trading program for NO_X and SO_2 in both countries. This section describes the development of analytical tools, the analysis of transboundary air quality, and the significant advances necessary to the consideration of cross-border trading, including shared emission inventories, integrated electricity and emissions modeling, and cross-border air quality modeling.

H.1 DEVELOPMENT AND DESCRIPTION OF JOINT ANALYTICAL TOOLS

The IPM and air quality modeling done for this feasibility study and, more specifically, the projections of potential impacts, demonstrate that we can analyze cap and trade and illustrate the type of effects that can be considered. The actual results are not meant for decision-making since scenarios selected were a test of the models, not actual options the U.S. and Canada would want to pursue. The results are illustrative. They do not represent a prediction of a future control regime or environmental policy. The results of economic, emissions, and air quality modeling are highly dependent upon the design of policy scenarios the U.S. and Canada would want to analyze. The study demonstrates that the IPM model could be used productively to assist the U.S. and Canada to further examine emission caps and cross-border trading. The study's illustrative results, below, show that additional valuable insight and information on Canada-U.S. air management activities, can result from IPM and air quality modeling.

H.1.1 U.S.-Canada Power Sector Background and Power Sector Model: The Integrated Planning Model

Historically, cap and trade programs in the United States have focused on the power sector, which is a significant source of emissions affecting air quality and a sector where reductions can be achieved in a cost-effective manner. Analysis done to support the emissions cap and trading feasibility study has concentrated on the power sector and various existing models that have been used in the development and design of cap and trade programs in the United States. This section provides background on and discusses important aspects of the power sector that relate to transboundary issues. In addition, this section provides some background on the development and enhancement of the modeling tools that were used to better understand potential impacts of both caps and cross-border emissions cap and trading in the United States and Canada.

H.1.1.1 The Power Sector in the United States and Canada

The U.S. and Canadian power sectors are significantly different in size, scope, and composition. In 2003, electric generating sources in the United States produced roughly 3,850 billion kilowatt hours (kWh) to meet electricity demand, while Canadian sources produced roughly 580 billion kWh. In the United States, over 70 percent of this electricity was produced through the combustion of fossil fuels, primarily coal and natural gas, while 26 percent of this generation was produced from fossil fuels in Canada (Figure H-1).

Electricity generation in Canada comes predominantly from hydroelectric units (60 percent); the remaining generation comes from fossil fuel units (26 percent), nuclear units (12 percent), and other units such as wind turbines. While hydro is the main source of generation nationally, in certain regions, such as Alberta, Saskatchewan, Ontario, New Brunswick, and Nova Scotia, coal combustion plays a significant role. In the United States, about half of all generation is produced from coal-generating facilities, dispersed throughout the country, with most of the coal capacity located in the eastern portion of the country. Figure H-2 is a map of both countries showing the population of existing U.S. and Canadian fossil fuel-fired power plants larger than 25 megawatts that are inputs to IPM. Table H-1 displays existing U.S. and Canadian capacity by source type.

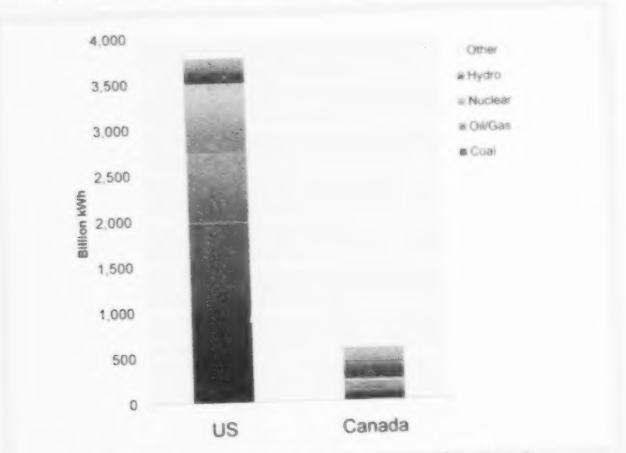
The burning of fossil fuels results in air emissions of SO_2 and NO_X, important precursors to the formation of fine particles ($PM_{2.5}$) and ozone, which contribute to serious negative environmental and health effects. The power sector is a major contributor of both these pollutants, and emissions of SO_2 and NO_X are essential to any discussions in the transboundary context. In 2003, the power sector in the United States accounted for 67 percent of total nationwide SO_2 emissions and 22 percent of total nationwide NO_X emissions. In 2002, in Canada, the power sector accounted for approximately 26 percent of total nationwide SO_2 emissions and 11 percent of nationwide NO_X emissions. (For more information, see Figure A-9 in Section A for pie graphs of SO_2 and NO_X emissions.)

The U.S. and Canadian power sectors are integrated, with electricity flowing back and forth, depending on seasonal demand. Canada is generally a net exporter of electricity to the United States, sending between 7 and 9 percent of the total power generated in Canada to the United States. Typically, Canadian sources sell power to the United States during peak demand periods, mostly from hydro. While electricity flows from Canada to the United States continue to exceed flows from the United States to Canada, the past several years have seen increasing flows from the United States to Canada. In 2003, the United States imported roughly 5 billion kWh, or about 0.1 percent of all U.S. electricity consumed.

H.1.1.2 Power Sector Model

In discussing the impacts of cap and trade, the primary focus in the United States has historically been the power sector. The U.S. EPA has extensive experience with analytical tools specific to the power sector that have helped inform and direct environmental policy for the past 15 years, beginning with the Acid Rain Program in 1990 and up through EPA's most recent regulatory cap and trade initiative, the Clean Air Interstate Rule (CAIR), promulgated in March 2005. The IPM model has been used to examine air pollution control policies for SO_2 and NO_X throughout the contiguous United States for the entire power system. As part of this feasibility study under the Border Air Quality Strategy, a module that reflects the Canadian power sector was developed and added to the existing IPM model of the U.S. power sector. In addition, the IPM model that reflects the U.S. power sector was improved and enhanced. In order to assess the impacts of emission reductions with and without cross-border emissions cap and trading between the two countries, the IPM model was run using illustrative modeling scenarios, where emission restrictions on SO_2 and NO_X were applied in both countries. In addition to the power sector modeling, air quality modeling was also performed.

Figure H-1 Electricity Generation in Canada and the United States, 2003



Source: U.S. Energy Information Administration and Statistics Canada.

Figure H-2 IPM Inputs of U.S. and Canadian Fossil Fuel-Fired Power Plants Showing Locations and Characteristics of the Plants Used in IPM

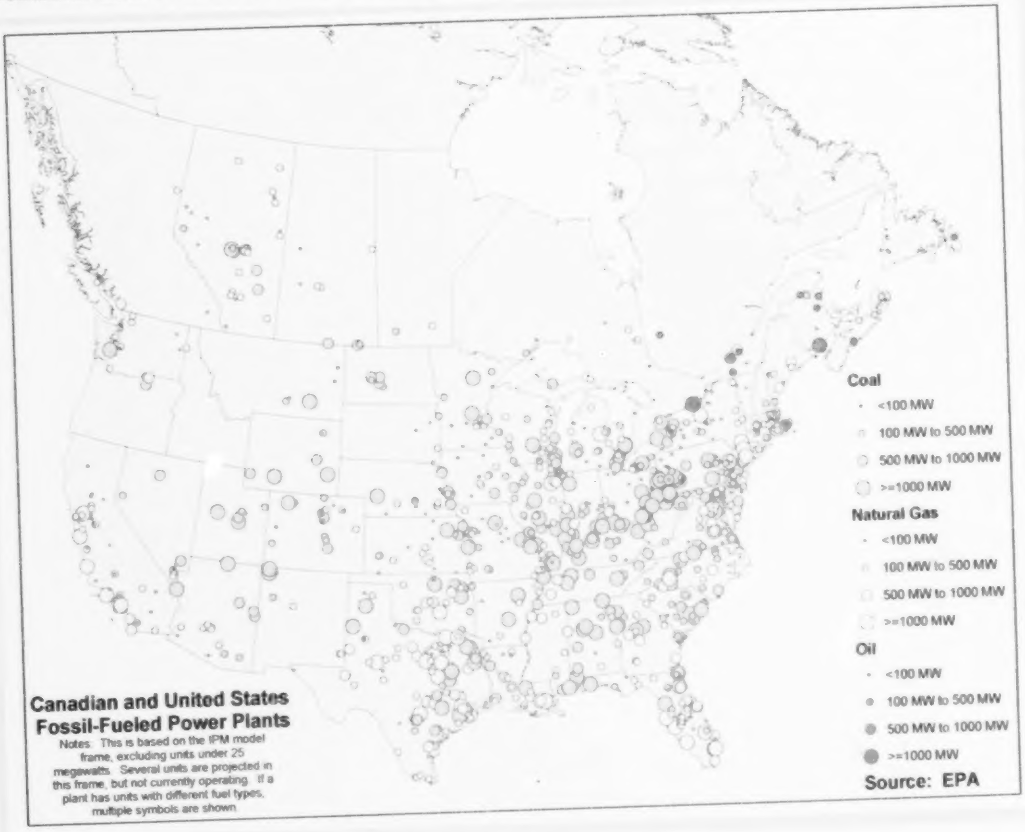

Canadian and United States Fossil-Fueled Power Plants
Notes: This is based on the IPM model frame, excluding units under 25 megawatts. Several units are projected in this frame, but not currently operating. If a plant has units with different fuel types, multiple symbols are shown.
Coal
<100 MW
100 MW to 500 MW
500 MW to 1000 MW
>=1000 MW
Natural Gas
<100 MW
100 MW to 500 MW
500 MW to 1000 MW
>=1000 MW
Oil
<100 MW
100 MW to 500 MW
500 MW to 1000 MW
>=1000 MW
Source: EPA

Table H-1 Existing U.S. and Canadian Electricity Generating Capacity by Source

Energy source	United States (2002)		Canada (2003)	
	Number of generators	Generator nameplate capacity (MW)	Number of generators	Generator nameplate capacity (MW)
Coal	1,566	338,199	58	16,901
Oil/gas	9,044	420,558	887	15,631
Nuclear	104	104,933	15	11,155
Hydro	4,157	96,343	1,493	70,374
Other	1,542	19,553	474	2,931
Total	16,413	979,586	2,927	116,991

Source: U.S. Energy Information Administration and Statistics Canada.

Development of the Canadian module of the IPM model grew out of recognition that emissions transport across the U.S.-Canada border and the growing interdependence and restructuring of the electricity markets in the two countries present Canadian and U.S. air quality policymakers with the challenge of coordinating approaches to limiting power plant emissions. Developing more sophisticated analytical tools to examine cross-border air quality issues was seen as an important step toward increasing understanding of emissions in the cross-border region and evaluating possible air quality policies. The Canadian IPM module was intended to meet the following goals:

- Represent the Canadian power sector (excluding industrial boilers), in support of analyzing transboundary emission cap and trading issues, and be compatible with similar analytical tools used by EPA.
- Provide analyses of the electric power sector in Canada in order to identify the distinctive geographic, technological, economic, financial, legal, operational, and environmental features that will need to be incorporated into a model of the Canadian electric power sector.
- Design, program, test, implement, and document a model of the Canadian power sector that would be able to run both independently and in combination with the U.S. models to perform cross-border emissions policy analysis.
- Provide outputs at the national, regional, and provincial levels and unit-level, point source emission values that can be used as inputs to atmospheric and health effects models.

The IPM model was seen as offering a number of important advantages in meeting these goals. IPM is a well-established model of the electric power sector, designed to help government and industry analyze a wide range of issues related to this sector. The model represents economic activities in key components of energy markets: fuel markets, emission markets, and electricity markets. Since the model captures the linkages in electricity markets, it is well suited for developing integrated analyses of the impacts of alternative regulatory policies on the power sector. In the past, applications of IPM have included capacity planning, environmental policy analysis and compliance planning, wholesale price forecasting, and asset valuation. IPM's representation of the electric power sector has achieved a high level of credibility growing out of an established record of use by a wide range of private and public sector clients and its extensive application in analyzing and developing emission policies in the United States. It is particularly well suited for modeling the operation of the North American electric power system due to its detail-rich depiction of the sector, its refined representation of the dispatch and capacity expansion behavior of electricity generating units, and its bottom-up representation of emissions, emission control technologies, and fuels. IPM also has a wide array of regulatory options for implementing emission reduction policies, ranging from traditional "command and control" policies to market-based cap and trade programs.

The IPM model offers the capability to project results down to the generating unit level, and it produces outputs that can be used in other models (e.g., atmospheric, deposition, health effects, cost/benefit models). Since EPA is already using IPM for modeling the U.S. electric power sector, there would be immediate structural compatibility between the U.S. and Canadian models. It also would allow Canada to take advantage of prior U.S. modeling work and expertise, thereby fostering more informed, faster, and cost-effective model development. Its applications for EPA are fully documented, and it has had a long history of public and expert review.

Canadian efforts focused on the Canadian IPM module, intended to provide a representation of the Canadian electric power sector comparable to the representation of the electric power sector in the implementation of the IPM model being used by EPA. The sector scope includes power sector generators that sell the majority of their output to the grid. The geographic scope includes all provinces. Although the IPM model is capable of modeling many pollutants in the electricity sector, including carbon dioxide, mercury, and particulate matter (PM), the pollutants of focus in the Canadian module are SO_2 and NO_X.

For the Canadian IPM module, a database of existing generating units was developed, including existing hydro, nuclear, fossil fuel, biomass, and other non-fossil fuel EGUs. The database also included the specific characteristics of these existing generating units, such as generation capacities, unit types, fuel types used, unit availabilities, emission rates, and heat rates. The Canadian module required characterizations of Canada's national and regional electricity demand, peak demand, and load duration curves by season as well as a characterization of transmission interconnection capacities, loss factors, and charges for the transmission grid connecting Canada's regions as well as the shared Canada-U.S. transmission grid.

Cost and performance characterizations were also developed for new generating units and environmental control technologies. Care was taken to maintain consistency with the U.S. IPM model assumptions by using the same basis for estimating cost and performance of generation and environmental control technologies. This was necessary to ensure that the results (e.g., trading opportunities, costs of compliance) would reflect real differences in the system characteristics (e.g., current control levels, emission rates, opportunities for reductions) and not the fact that the U.S. and Canadian models assumed that control technologies have fundamentally different costs. It was critical that the inputs to the two models reflected real differences between the two countries.

Financial assumptions were developed based on both "expert" input from Canadian federal government departments and the EPA IPM model Base Case (v. 2.1.6). Fuel price structures and projections were developed for coal, natural gas, fuel oil, orimulsion, biomass, and nuclear fuel. Existing federal and provincial laws and regulations that affect NO_X and SO_2 emissions from the electric power sector were also taken into account.

The development of the Canadian module for the IPM model could not have been completed without the support, advice, experience, guidance and knowledge of the EPA. A detailed technical report documenting all of the assumptions and inputs in the Canadian module of the IPM model is available on Environment Canada's Clean Air online Web site at **http://www.ec.gc.ca/cleanair-airpur/can-us_border_air_quality_strategy_wsd6f2621E-1_en.htm**. EPA IPM model documentation is also available on EPA's Web site at **http://www.epa.gov/airmarkets/epa-ipm/**.

H.1.1.3 Post-Processing of IPM Model Power Sector Emission Projections for Air Quality Modeling

In order to perform air quality modeling using IPM power sector emission projections, EPA uses a process to convert and enhance IPM output files to better reflect exact EGU conditions, in terms of emissions and unit characteristics. The IPM post-processing methodology involves taking IPM output files and transforming them into air quality model input files. It enhances the IPM outputs by adding additional parameters important for air quality modeling, such as estimates of additional emissions, stack parameters, unit information, disaggregating and siting units, and adding identifiers.

Post-processing IPM model files into air quality model input files has occurred for almost a decade for the U.S. power sector. This process was expanded to include the Canadian power sector. Through collaboration between EPA and Environment Canada, the necessary location and configuration data for the Canadian EGUs were gathered and air quality model input files were developed. This represents significant progress in the development of air quality modeling related to the power sector in North America, as air quality models have not previously had such precise information regarding Canadian EGUs. Although there is still additional work to be done to improve the information that is now available, this marks an important development that was instrumental in analyzing cross-border cap and trading scenarios.

H.1.2 Air Quality Models

Air quality modeling was performed by Canada and the United States to evaluate the air quality impact of an illustrative cross-border cap and trade scenario. The two countries have a long history of experience in developing and applying air quality models to analyze air pollutant emission control scenarios. Both countries have performed joint air quality modeling in the past, notably as part of the National Acid Precipitation Assessment Program (NAPAP) studies, undertaken in the 1980s, and most recently in preparing the Canada-U.S. Ground-Level Ozone and Transboundary PM Science assessments. The work in this study builds on the joint modeling that was done as part of the most recent Canada-U.S. Transboundary PM Science Assessment released in February 2005 and available online at **http://www.ec.gc.ca/pdb/can_us/canus_links_e.cfm**.

U.S. air quality modeling for $PM_{2.5}$, visibility, and deposition was conducted using the Community Multiscale Air Quality Model (CMAQ). The CMAQ model is the result of scientific and technical collaboration by hundreds of researchers from around the world over the last 10 years, resulting in a state-of-the-art modeling system for investigating the impact of emissions upon air quality indicators of interest, such as $PM_{2.5}$ concentrations, acid deposition, and visibility. The CMAQ "base case" modeling scenario used in this study was based on the work performed and documented in detail for the Clean Air Interstate Rule (see the air quality modeling technical support document for details of the model configuration, base year emission inventory, and meteorology at **http://www.epa.gov/cair/technical.html**). The base year for this study is 2001 as in the EPA's recent CAIR analysis, with updated estimates of Canadian emission sources provided as part of this feasibility study by Environment Canada. CMAQ was used to provide illustrative results as to air quality impacts of a cross-border emissions cap and trade scenario. As detailed in Table H-2, the annual average $PM_{2.5}$ concentrations, visibility, and deposition estimates for each of the emission scenarios in two modeled years are provided.

Canadian episodic modeling was performed using AURAMS (A Unified Regional Air Quality Modelling System). AURAMS simulations were performed for two episodes (one in summer, one in winter) to evaluate the relative impact

Table H-2 Figures Demonstrating Projected Changes in Environmental Endpoints from Air Quality Modeling of an Illustrative U.S.–Canada Cross-Border Emissions Cap and Trade Scenario

Model	Period Modeled	Parameter	Figure
CMAQ	Annual	Average ($PM_{2.5}$)	15-17
AURAMS	Winter Episode	Average ($PM_{2.5}$)	18
AURAMS	Summer Episode	Average ($PM_{2.5}$)	19
AURAMS	Summer Episode	Peak (O_3)	20
CMAQ	Annual	Total S Deposition	21
CMAQ	Annual	Total Oxidized N Deposition	22
CMAQ	Annual	Visibility (Deciview)	23

of each scenario modeled by IPM. The summer simulation spans the period from July 1 through July 19, 1995, and covers a regional ozone episode that is also associated with high levels of PM. The winter simulation covers the period from February 1 through February 16, 1998. The February 1998 simulation period was chosen because of the occurrence of a wintertime regional PM episode over a large portion of northeastern North America during the second week of the period.

In both the U.S. CMAQ and Canadian AURAMS modeling, for each scenario modeled, the emissions from electric power plants predicted by IPM were used to replace power plant emissions, and all other emissions were held constant to the 2001 base year simulation values. This approach resulted in the observed changes in model output being isolated to the effects of the given cap and trade scenario.

H.1.2.1 The AURAMS Air Quality Model

AURAMS is a unified regional air quality modeling system developed by Environment Canada for research and policy applications. Designed as a "one-atmosphere" system, AURAMS allows the study of interactions between NO_x, VOCs, ammonia, ozone, and primary and secondary PM through aqueous, gaseous, and heterogeneous reactions. AURAMS' credentials have been documented in the peer-reviewed literature (Bouchet et al., 2003; Makar et al., 2003, 2005; Gong et al., 2005), and the model has been used for both joint U.S.-Canada assessments (Transboundary PM Science Assessment) and joint U.S.-Canada experiments (McKeen et al., 2005).

AURAMS version 1.1 was used for the feasibility study. Updates from the version used for the Canada-U.S. Transboundary PM Science Assessment included an extension of the modeling domain to cover the western part of the continent, optimization of the chemistry modules, and inclusion of a plume-rise calculation. Figure H-3 depicts the AURAMS modeling domain, encompassing all Canadian provinces and U.S. states between 30 and 60 degrees north latitude with a horizontal resolution of approximately 42 km by 42 km.

H.1.2.2 The CMAQ Air Quality Model

The CMAQ modeling system is a comprehensive three-dimensional grid-based Eulerian air quality model designed to estimate particulate concentrations and deposition over large spatial scales (Dennis et al., 1996; Byun and Ching, 1999; Byun and Schere, 2004). The CMAQ model is a publicly available, peer-reviewed, state-of-the-science model consisting of a number of science attributes that are critical for simulating the oxidant precursors and nonlinear organic and inorganic chemical relationships associated with the formation of sulfate, nitrate, and organic aerosols. CMAQ also simulates the transport and removal of directly emitted particles that are

Figure H-3 Map of the AURAMS Modeling Domain Used in the Feasibility Study

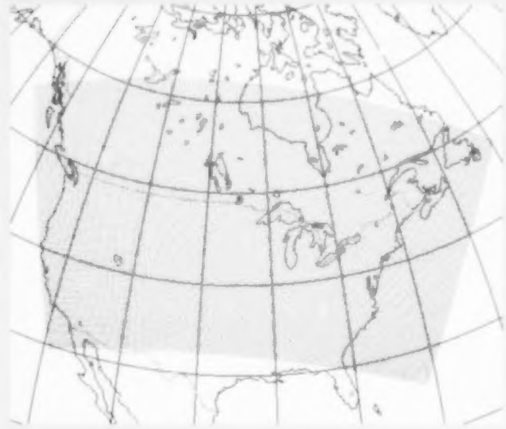
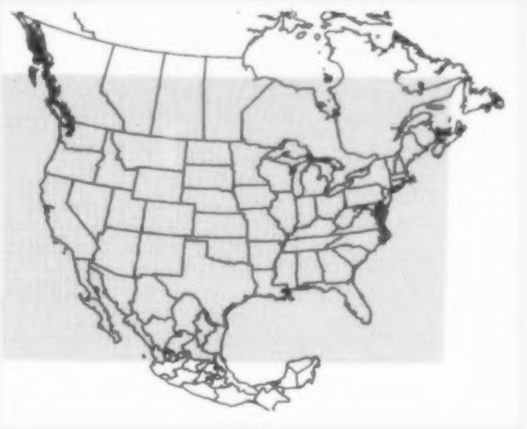


Figure H-4 Map of the CMAQ Modeling Domain Used for CAIR



speciated as elemental carbon, crustal material, nitrate, sulfate, and organic aerosols.

Version 4.3 of CMAQ (Byun and Schere, 2004) was used for this feasibility study. This version reflects updates to earlier versions in a number of areas to improve the underlying science and address comments from the peer review. This version of the model is the same as that applied for CAIR modeling and as specified in detail in the CAIR air quality modeling technical support document (TSD) (**http://www.epa.gov/cair/pdfs/finaltech02.pdf**). In addition, the CMAQ meteorological, initial, and boundary conditions used here are the same as those used in the CAIR modeling, as specified in detail in the CAIR TSD. Finally, the CMAQ modeling domain was also the same as that used for CAIR analysis, encompassing the lower 48 states and portions of Canada and Mexico (as shown in Figure IV-1 provided at the end of Section IV of the CAIR TSD and reproduced here as Figure H-4). The domain extends from 126 degrees to 66 degrees west longitude and from 24 degrees north latitude to 52 degrees north latitude. The horizontal grid cells are approximately 36 km by 36 km. The modeling domain contains 14 vertical layers, with the top of the modeling domain at about 16,200 meters, or 100 millibars (mb).

H.2 ILLUSTRATIVE MODELING SCENARIOS FOR CROSS-BORDER SO_2 AND NO_X EMISSIONS CAP AND TRADING

Using the enhanced version of IPM, which is capable of modeling an integrated U.S.-Canada power system, various illustrative modeling scenarios were developed to assess the potential impacts of caps and cross-border trading. For the emission caps on the electricity sector in a cap and trade system, a decision was made to develop SO_2 and NO_X emission caps based upon the levels set in the U.S. Clear Skies proposal of 2003. This legislative proposal has been analyzed and modeled in the United States. It must be emphasized that these cap levels were used for illustration purposes only.

The primary scenario used for analysis, the Trading Scenario, is one that applies Clear Skies (2003) cap levels for SO_2 and NO_X in both the United States and Canada and allows cross-border trading. The Canadian caps were developed by applying the percent reduction that roughly reflects what Clear Skies (2003) is designed to achieve in the United States. The U.S. and Canadian caps were then combined to obtain one joint SO_2 cap and one joint NO_X cap for both countries. Note that all fossil fuel-fired

Table H-3 Illustrative Emission Caps for the United States and Canada

		Emission caps (million short tons)[1]		
	Year	**United States**	**Canada**	**Joint cross-border caps**
SO_2	2010	4.5	0.5	5.0
	2018	3.0	0.3	3.3
NO_X East	2008	1.6	0.05	1.6
	2018	1.2	0.04	1.2
NO_X West	2008	0.5	0.09	0.6

[1] One tone is equal to 1.1 short tons.

EGUs with a capacity greater than 25 MW and producing electricity for sale to the grid are covered by the SO_2 and NO_X caps in this scenario.

A base case, or reference case, was also modeled. The Base Case includes all existing pollution reduction programs that were in place in 2004 and provides a comparison point to determine the incremental impacts of a given emission reduction scenario. The model's base case incorporates, for the United States, Title IV of the Clean Air Act (the Acid Rain Program), the NO_X SIP call, various New Source Review (NSR) settlements, and several state rules affecting emissions of SO_2 and NO_X. The Base Case does not include EPA's recent regulation, CAIR. For Canada, the Base Case includes all current requirements for the power sector for SO_2 and NO_X emissions. In terms of emission caps in Canada's base case, emission caps exist only in Ontario and Quebec, where there are annual NO_X caps in place to be met by 2007. The Base Case is used to provide a reference point to compare environmental policies and assess their impacts and does not reflect any future predicted scenario.

The caps for each country, along with the combined caps, are shown in Table H-3. For NO_X, two separate caps were modeled to reflect Clear Skies (2003), where separate NO_X zones were proposed (see Figure H-5), along with a national SO_2 cap.

Finally, a third scenario, "Clear Skies Act (CSA) in U.S. only," applied the Base Case to Canada with no additional emission reductions and no cross-border trading along with Clear Skies caps and trading in the United States. This third scenario provided the basis for comparing results in the United States with and without cross-border trading.

In addition to the main Trading Scenario, various sensitivity runs (see Section H.3.6 for more information) were also modeled to help answer some important questions regarding trading, such as the benefits and advantages of trading, as well as questions concerning the stringency and equivalency of the cap levels for each country.

H.3 RESULTS FOR THE POWER SECTOR USING THE INTEGRATED PLANNING MODEL

The Trading Scenario impacts each country's respective power sector differently, since there are significant power sector differences in each country. Because total emissions are considerably lower in Canada than in the United States, the magnitude of reductions in Canada will be much less than the reductions one would anticipate in the United States. To provide a general sense of the potential impacts of caps and cross-border trading and how those impacts are unique to each country, IPM model results for both countries are presented.

H.3.1 Emissions

Figures H-6, H-7, and H-8 show, for the Base Case and Trading Scenario, the state- and

Figure H-5 NO$_X$ East and West Model Regions for Illustrative Analysis

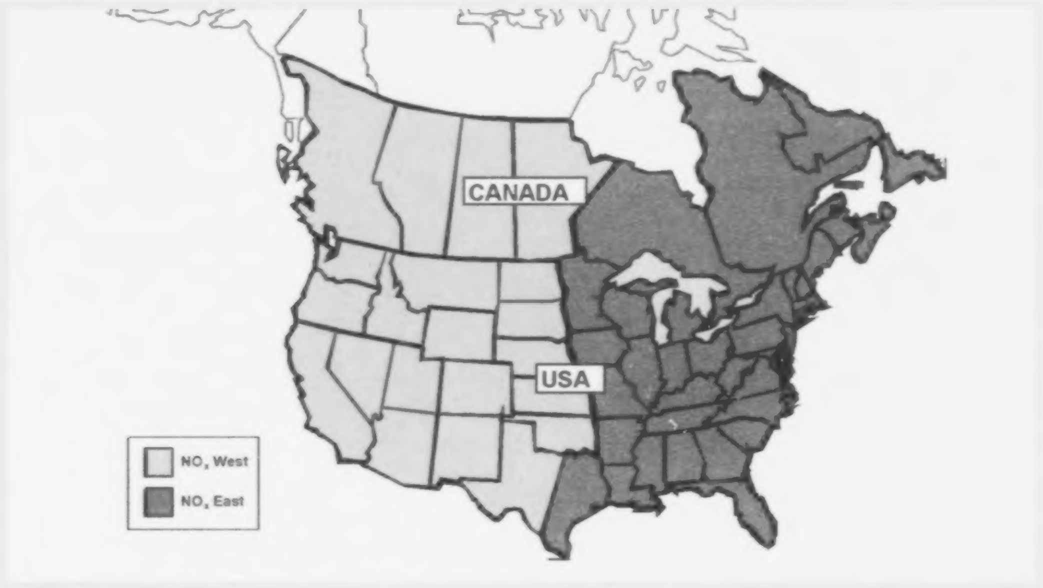
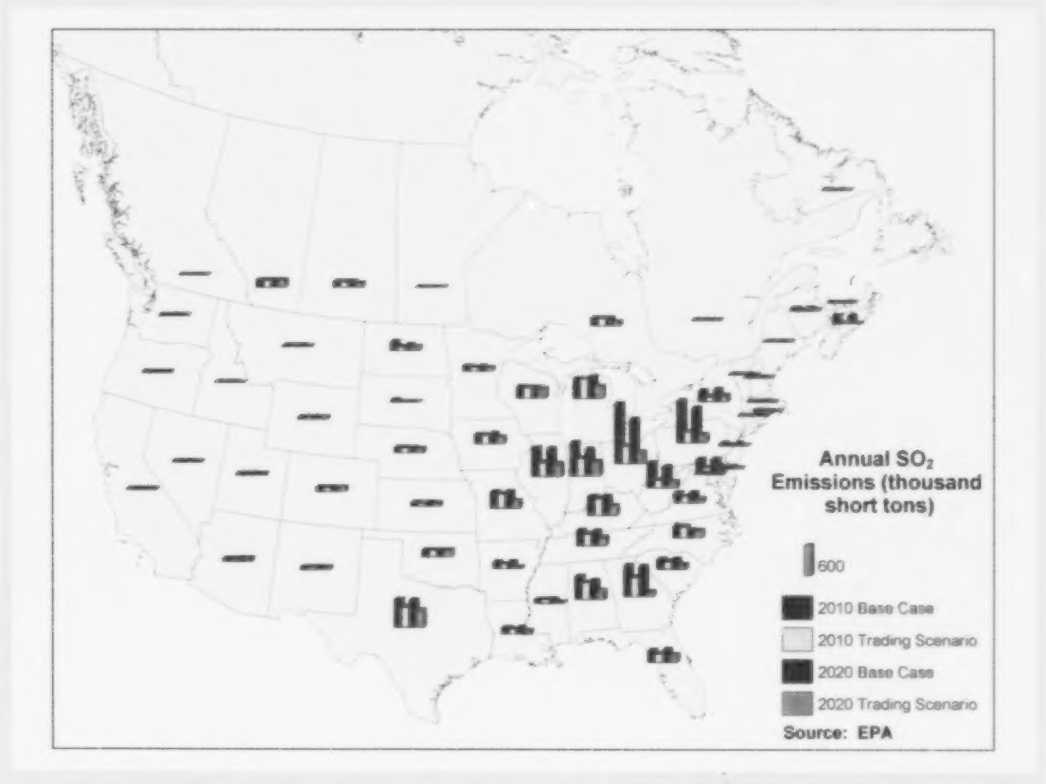
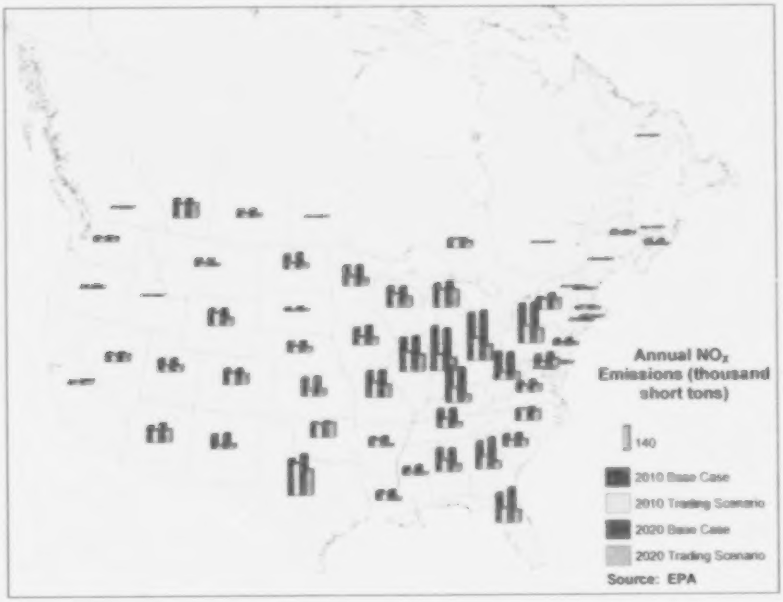

CANADA
USA
NOx West
NOx East

Figure H-6 Annual SO$_2$ Emissions in 2010 and 2020, Comparing the Base Case (with no caps in Canada) with the Illustrative Trading Scenario (with caps in Canada and cross-border trading)


Annual SO₂ Emissions (thousand short tons)
600
2010 Base Case
2010 Trading Scenario
2020 Base Case
2020 Trading Scenario

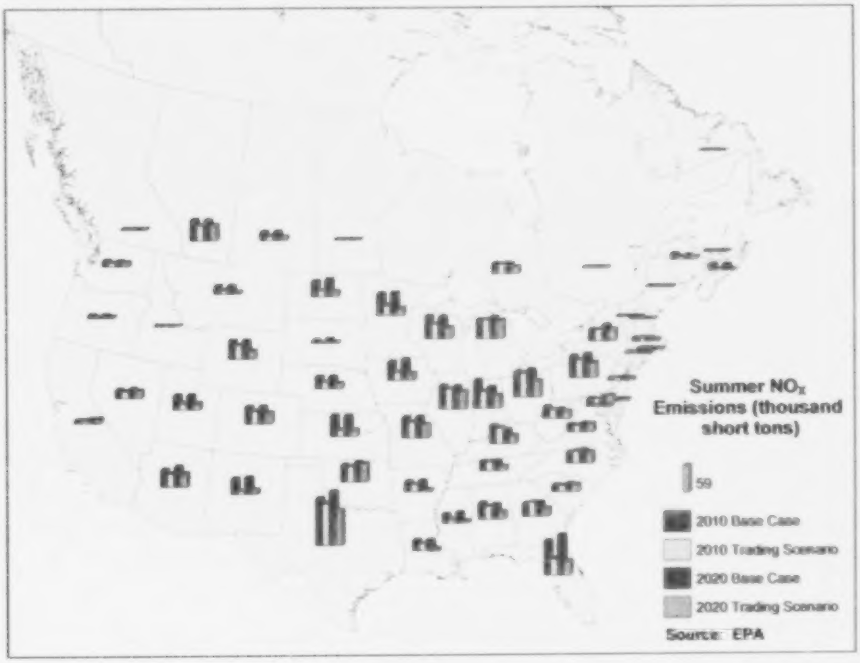
Source: EPA

Figure H-7 Annual NO_X Emissions in 2010 and 2020, Comparing the Base Case (with no caps in Canada) with the Illustrative Trading Scenario (with caps in Canada and cross-border trading)


Annual NO_X Emissions (thousand short tons)
140
2010 Base Case
2010 Trading Scenario
2020 Base Case
2020 Trading Scenario

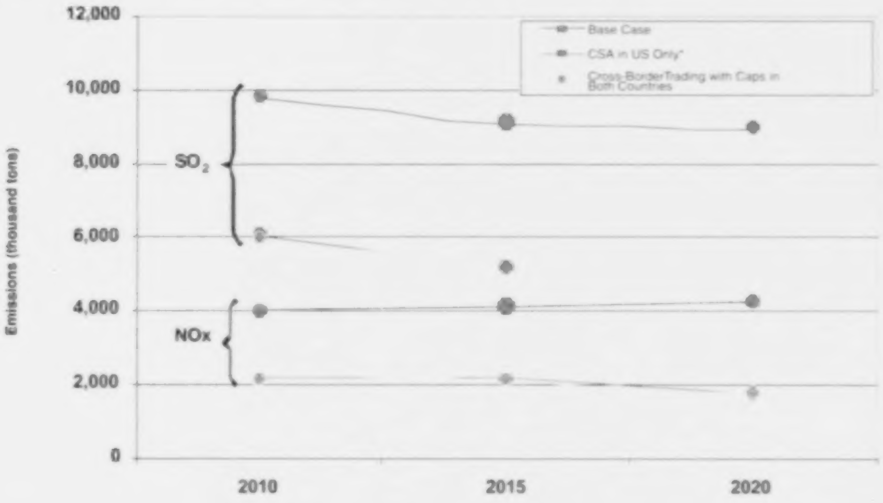
Source: EPA

Figure H-8 Summer NO_X Emissions in 2010 and 2020, Comparing the Base Case (with no caps in Canada) with the Illustrative Trading Scenario (with caps in Canada and cross-border trading)


Summer NO_X Emissions (thousand short tons)
59
2010 Base Case
2010 Trading Scenario
2020 Base Case
2020 Trading Scenario

Source: EPA

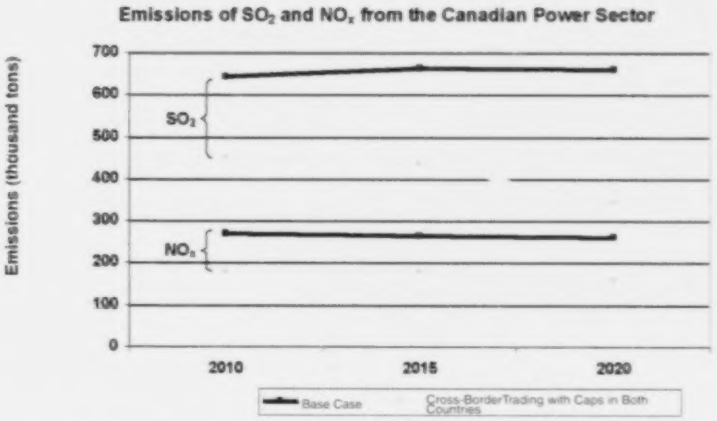
Figure H-9 Emissions of SO_2 and NO_X from the U.S. Power Sector – Base Case, Clear Skies U.S., and the Illustrative Trading Scenario



Note: Lines are on top of each other as the scenario results are virtually the same.

Source: IPM

Figure H-10 Emissions of SO_2 and NO_X from the Canadian Power Sector – Base Case and the Illustrative Trading Scenario



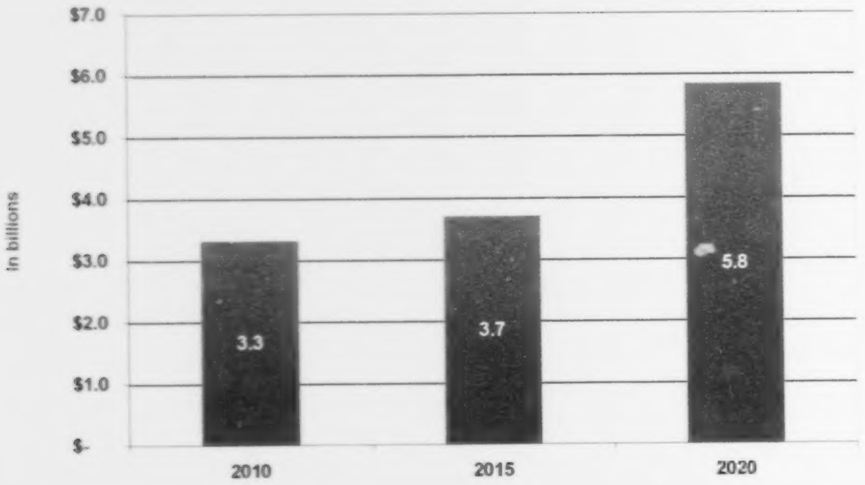
Source: IPM

province-level 2010 and 2020 annual SO_2, annual NO_X, and summer NO_X emissions, respectively.

Modeling the Trading Scenario with caps and cross-border trading show broad reductions in SO_2 and NO_X emissions in both countries. Specifically, for the United States (as seen in Figure H-9), the projections from IPM are similar to the original Clear Skies (2003) analysis.

In Canada (Figure H-10), with emission caps under the Trading Scenario, emissions of NO_X and SO_2 are projected to be roughly 30 percent lower in 2010, relative to the Base Case, and 40 to 50 percent lower in 2020.

Figure H-11 **Annual Incremental Costs to the Base Case for the U.S. Power Sector of Illustrative Trading Scenario**



Source: IPM

H.3.2 Allowance Prices

Allowance prices for SO_2 and both NO_X zones are not greatly altered when Canadian sources are capped and included in a cross-border trading program (the Trading Scenario) from what they would be under the Clear Skies U.S. only case. In 2015, the NO_X West allowance prices increase when Clear Skies (2003) is expanded to include Canada, the only notable difference.

H.3.3 Costs

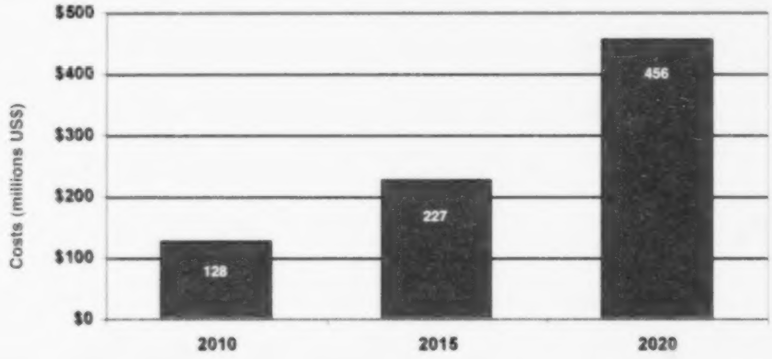
For the United States, the total annualized incremental cost of Clear Skies (2003) does not change significantly whether there is cross-border trading with Canada or not (Figure H-11). The incremental cost represents the additional costs to the power sector of reducing emissions, as required in the cap and trade program. The difference in costs is roughly between $100 million to $180 million (U.S. 1999) as a result of slight changes in the way in which the power sector chooses to meet the emission caps in the most cost-effective manner.

As expected, in Canada, by requiring the power sector to achieve emission reductions through caps, the Trading Scenario with cross-border emission caps and trading will cost the electricity sector in Canada more than under the Base Case, where there are no emission reductions. Based on the modeling that was done, the total annualized incremental cost of capping the electricity sector in Canada under the illustrative cross-border emissions cap and trading scenario ranges from about $130 million U.S. in 2010 to roughly $460 million U.S. in 2020 (see Figure H-12).

H.3.4 Electricity Generation

As projected in IPM, the United States will eventually be a net exporter of electricity to Canada in the future, which is consistent with general trends in electricity production over the last 10 to 20 years. The Trading Scenario with caps and cross-border trading, does not alter this forecast in any meaningful way, since the change in the amount of electricity sent to Canada from the United States represents less than one-tenth of a percent of total U.S. generation and less than seven-tenths of a percent of total Canadian generation. By 2020, Canada is projected to import net electricity of

Figure H-12 Annual Incremental Costs to the Canadian Power Sector of Illustrative Trading Scenario



Source: IPM

8.1 terrawatt hours (TWh) under the caps and cross-border trading scenario and 12 TWh under the base case scenario. Therefore, the same trend is observed in the Base Case as with caps and cross-border trading: less Canadian reliance on imported U.S. electricity in 2020 with the caps and cross-border trading scenario relative to the Base Case.

H.3.5 Generation Mix

The total generation mix in the United States is not changed in any significant way (Figure H-13). Similarly, the total generation mix in Canada is not altered significantly with caps and cross-border trading (Figure H-14). There are minimal shifts in the generation mix with caps and cross-border trading compared with the Base Case. Canadian natural gas-fired generation is projected to increase slightly, while coal-fired generation is projected to decline somewhat in the caps and cross-border trading scenario.

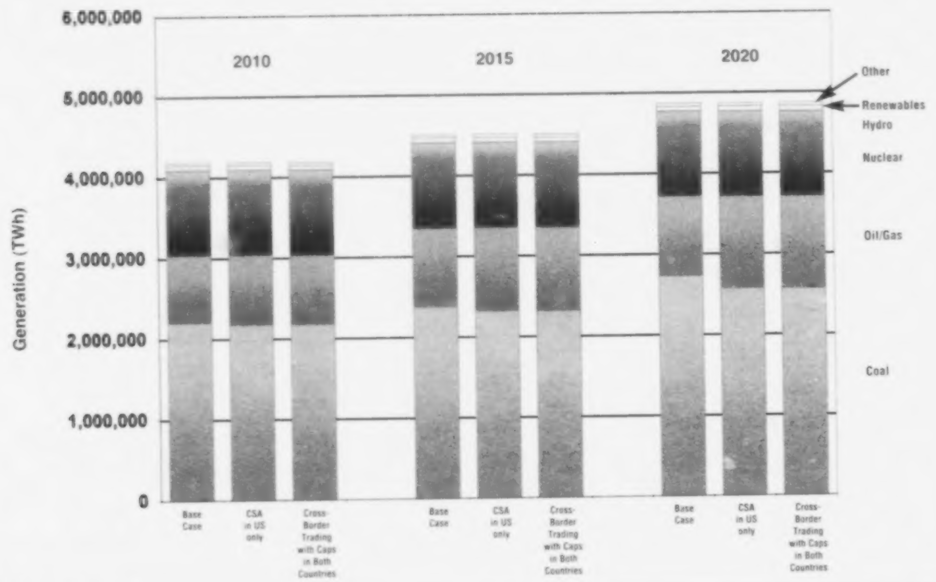
H.3.6 Sensitivity Analyses using IPM

To help inform the issue of caps and cross-border trading, sensitivity analyses were conducted using IPM to answer questions regarding the benefits of cap and trade to both countries and the levels of reductions or costs that are possible in Canada and if emission reductions were implemented by the power sector in Canada. The sensitivity runs also analyzed the impact of cross-border trading with a tighter SO_2 cap in Canada, the difference in costs and emissions in Canada between emission caps on the Canadian power sector with and without cross-border trading, and the impacts of an alternative, less flexible control strategy. (It is important to note that the analysis only modeled trading in Canada when there was cross-border trading available).

The sensitivity analyses show clearly that the level of the cap has a major impact on costs to the power sector, the distribution of the costs, the location of emission reductions, the extent of emission reductions, and the extent of the air quality and environmental benefits. Applying a tighter Canadian SO_2 cap when allowing cross-border trading resulted in additional reductions and slightly higher costs in both countries.

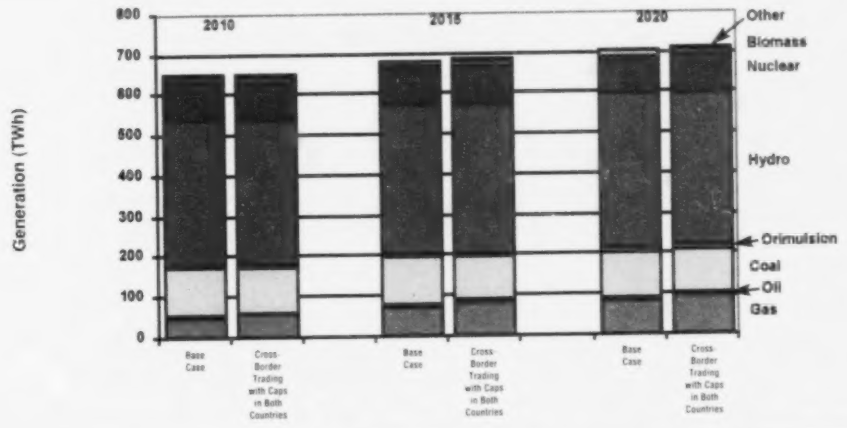
Further, the sensitivity analyses show that meeting the emission reduction limits in the Canadian power sector would be significantly less expensive if cross-border trading were available. The analyses demonstrate that because the cost to the power sector of achieving the emission reductions is lower with cross-border trading than without, if cost is the driver, the power sector could afford to reduce

Figure H-13 U.S. Generation Mix – Base Case, Clear Skies U.S., and the Illustrative Trading Scenario



CSA = Clear Skies (2003)
Source: IPM

Figure H-14 Canadian Generation Mix – Base Case and the Illustrative Trading Scenario



Source: IPM

significantly fewer emissions if cross-border trading were not available. The primary reason for these results is the flexibility that trading allows, since greater flexibility lets sources find the most cost-effective way to achieve emission reductions. In Canada, the same level of emission reductions without flexibility (i.e., with no cross-border trading) could result in costs of roughly $130-$230 million more, depending on the year. Additionally, the same level of costs without that same flexibility (i.e., with no cross-border trading) would likely achieve fewer SO_2 emission reductions (80,000 to 125,000 tons less) and fewer NO_X emission reductions (35,000 to 45,000 tons less), depending on the year in question.

These results reaffirm what has been the U.S. experience with existing cap and trade programs. Cap and trade programs achieve the required emission reductions in a more cost-effective and efficient manner than less flexible control requirements. In addition, many factors in a cap and trade program will influence the costs of reducing emissions, the amount of emission reductions, and where those reductions occur. Additional work needs to be undertaken to further explore these issues in a cross-border emissions cap and trading context.

H.4 RESULTS FROM AIR QUALITY MODELING

Air quality modeling was carried out in the United States and Canada to determine the impacts of caps and cross-border trading on air quality, acidification, and visibility. In particular, the air quality modeling looked at the resulting concentrations in the air of fine particles ($PM_{2.5}$) and ozone, as well as acidification (sulfur and nitrogen deposition) and visibility (in deciviews).

Building on the scenarios developed for the joint IPM modeling, the air quality modeling starts from the same base case in which the United States incorporates Title IV of the Clean Air Act (the Acid Rain Program), the NO_X SIP call, various NSR settlements, and several state rules affecting emissions of SO_2 and NO_X. The Base Case does not include EPA's recent regulation, CAIR, promulgated in March 2005. Canada has current requirements but no power sector caps for SO_2 and NO_X in place (except in Ontario and Quebec, where there are annual NO_X caps to be met by 2007). The Base Case is used to provide a reference point to compare environmental policies and assess their impacts and does not reflect a future predicted scenario. The air quality modeling compares this Base Case to the Trading Scenario that applies the U.S. Clear Skies (2003) cap levels for SO_2 and NO_X in Canada, establishing the cap levels in Canada using percent reductions that roughly reflect the levels that Clear Skies (2003) is designed to achieve in the United States and allowing cross-border trading between the two countries.

H.4.1 Annual $PM_{2.5}$

Figures H-15 and H-16 show annual percent $PM_{2.5}$ reductions across the domain from modeling using the CMAQ model for the years 2010 and 2020. The figures indicate significant regional reductions in annual $PM_{2.5}$ over a broad geographic area covering the eastern United States and Canada. Reductions of 10 to 20 percent occur over significant areas of eastern North America in 2010 and are maintained and expanded through 2020 under the modeled cross-border cap and trade scenario. Most significant improvement is observed in the mid-Appalachian area of the United States, with smaller, but noticeable, improvements extending well into Ontario and across New England and eastern Canada. With caps and cross-border trading, broad regional reductions in fine particles are achieved over the significant cross-border receptor area in eastern North America in this illustrative scenario.

In Figure H-17, with caps and cross-border trading, the model projects an absolute improvement in the average concentration of fine $PM_{2.5}$ of 1 to 3 micrograms per cubic meter (µg/m^3) for broad areas of eastern North America in 2020.

H.4.2 Absolute Change in Fine Particles with Emission Reductions and Trading during a Winter Episode

Using AURAMS to model a winter episode when, generally speaking, the $PM_{2.5}$ composition is less influenced by SO_2 emission reductions, shows the main decrease in $PM_{2.5}$ concentrations occurring over most of Iowa and neighboring states, with smaller decreases observed in select parts of Canada (Figure H-18). At the same time a small area of increased $PM_{2.5}$ concentration can be

Figure H-15 Percent Change in Annual Fine Particles with Emission Reductions under Illustrative Trading Scenario Compared to Base Case in 2010 (CMAQ)

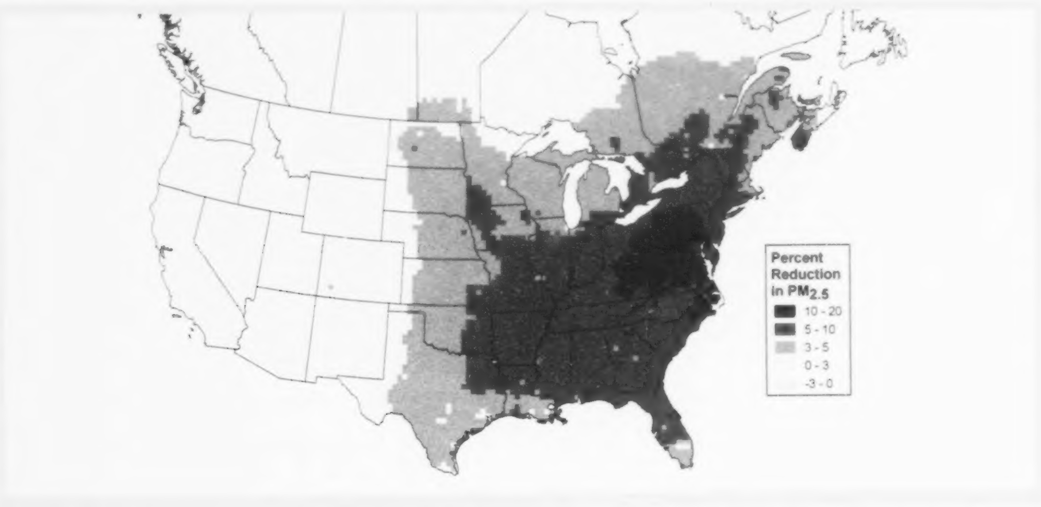
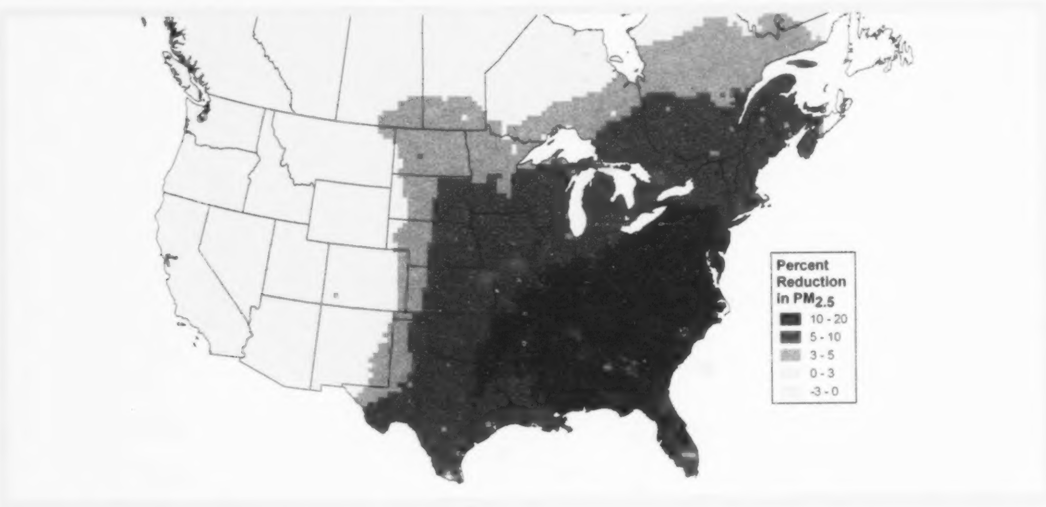


Figure H-16 Percent Change in Annual Fine Particles with Emission Reductions under Illustrative Trading Scenario Compared to Base Case in 2020 (CMAQ)



observed over Kentucky. This small increase in PM mass is due to a change in the sulfate-to-nitrate ratio where, under winter conditions, nitrate formation compensates for lower ambient sulfate levels compared to the annual simulations. The decrease in concentration is more limited in spacial extent and intensity, implying that more of the PM decrease in concentration occurs during other seasons.

H.4.3 Absolute Change in Fine Particles with Emission Reductions and Trading during a Summer Episode

As seen in Figure H-19, the PM concentration change from the AURAMS model during a 10-day summer episode shows large-scale reductions over most of the eastern part of the continent on the order of 1 to 5 µg/m^3, with significant areas showing even greater reductions, particularly in the United States. This represents reductions on the order of 15 to 25 percent in some areas.

Figure H-17 **Absolute Change in Annual Fine Particles (ug/m³) with Emission Reductions under Illustrative Trading Scenario Compared to the Base Case in 2020 (CMAQ)**

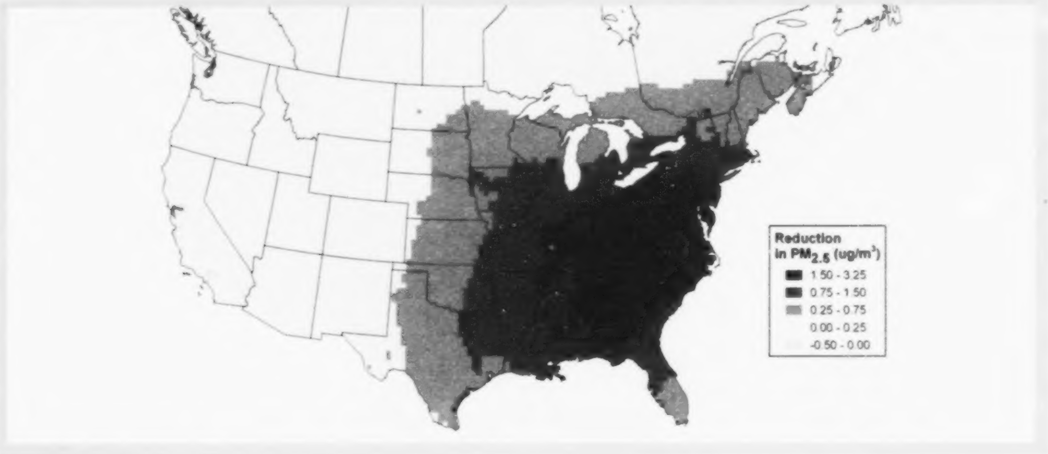
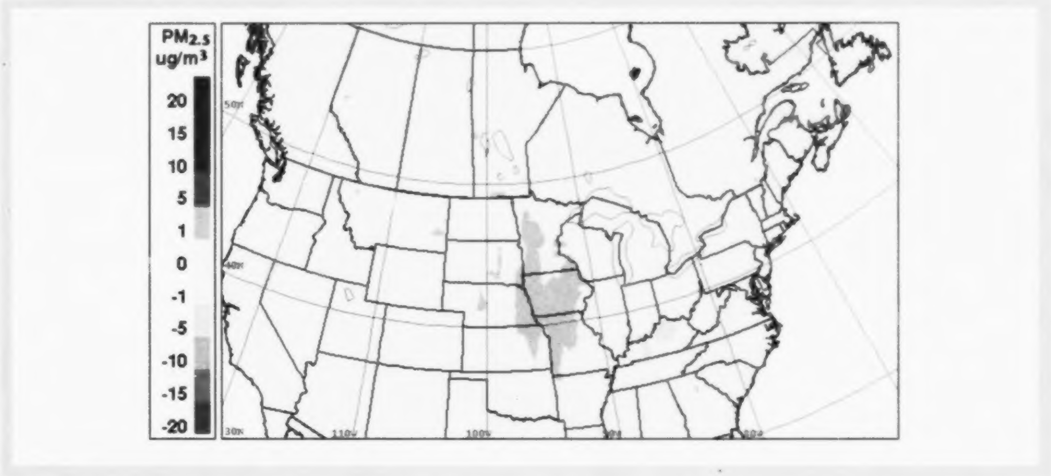


Figure H-18 **Absolute Difference in $PM_{2.5}$ Concentration (µg/m³), Comparing Illustrative Trading Scenario to the Base Case during the Winter Episode for 2020 (AURAMS)**



Decreases in PM concentration are also observed in the eastern Canadian provinces, particularly Ontario and Quebec, but also, to a lesser extent, in the Maritimes, Saskatchewan, and Alberta. These findings from the AURAMS model, relative to location and extent of $PM_{2.5}$ reductions, are compatible with the findings from the CMAQ model done on an annual basis.

H.4.4 Absolute Change in Ozone with Emission Reductions and Trading during a Summer Episode

Results from AURAMS for the 10-day summer episode in Figure H-20 show large-scale reductions (blue areas) in ozone concentrations over a broad geographic area from caps and cross-border trading on the order of 1 to 5 parts per billion (ppb).

Figure H-19 **Absolute Difference in $PM_{2.5}$ Concentration (ug/m³), Comparing Illustrative Trading Scenario to the Base Case during the Summer Episode for 2020 (AURAMS)**

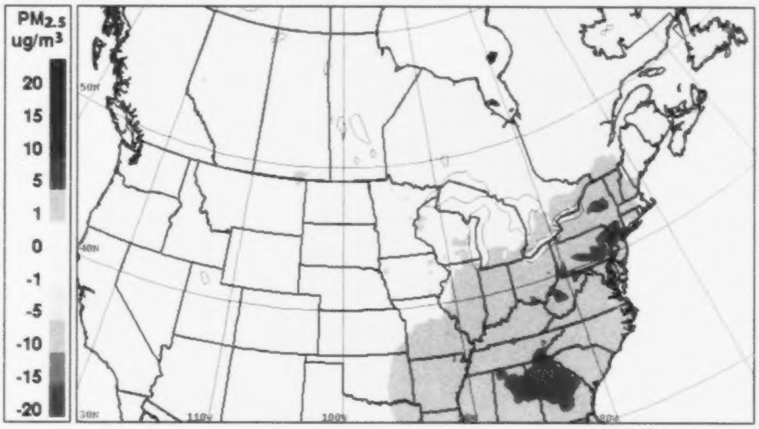
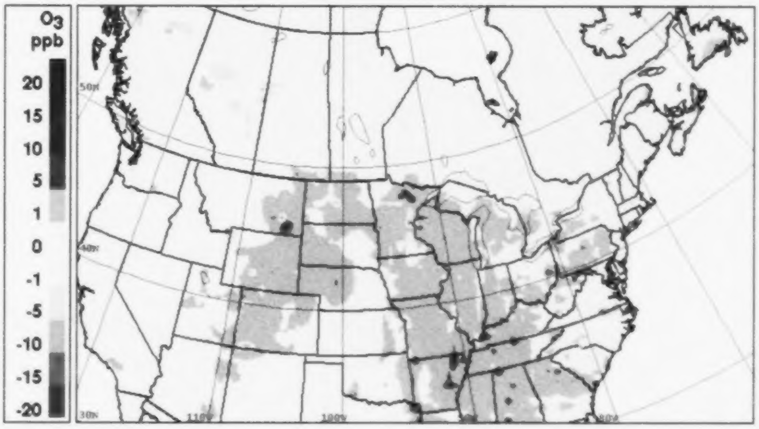


Figure H-20 **Absolute Difference between Illustrative Trading Scenario to the Base Case for Ground Level Ozone Daily Maximum (ppb) during the Summer Episode for 2020 (AURAMS)**



For Canada, Figure H-20 presents a general decrease in ozone concentrations in the border regions and the Maritimes. In localized areas, including southern British Columbia's Lower Fraser Valley, air quality is below the standard for ozone but public interest is high. The modeling shows that caps with cross-border trading would result in reductions in ozone on the order of 1 to 5 ppb in these populated areas. In other parts of Canada, and a few locations in the U.S., the AURAMS simulation for this one 10-day episode in the summer shows slight localized increases in ozone in urban areas and some rural locations downwind of major plants. An analysis of the ozone precursors has shown that these slight increases of just over 1 ppb are due to less NO_X being available to destroy ozone, as a result of the reductions in NO_X emissions under the caps with cross-border trading scenario. (See Seinfeld and Pandis, 1998).

Figure H-21 Percent Change in Sulfur Deposition with Emission Reductions under Illustrative Trading Scenario Compared to Base Case in 2020 (CMAQ)

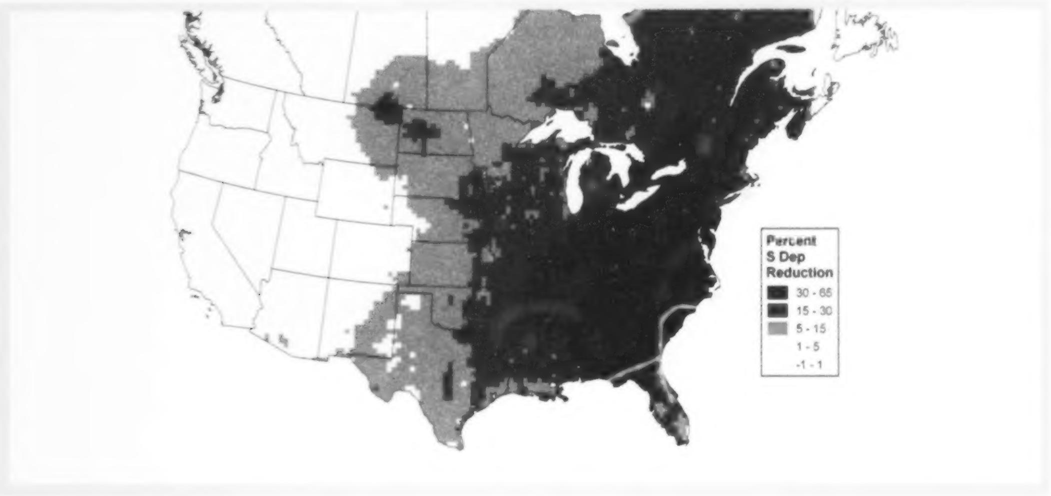
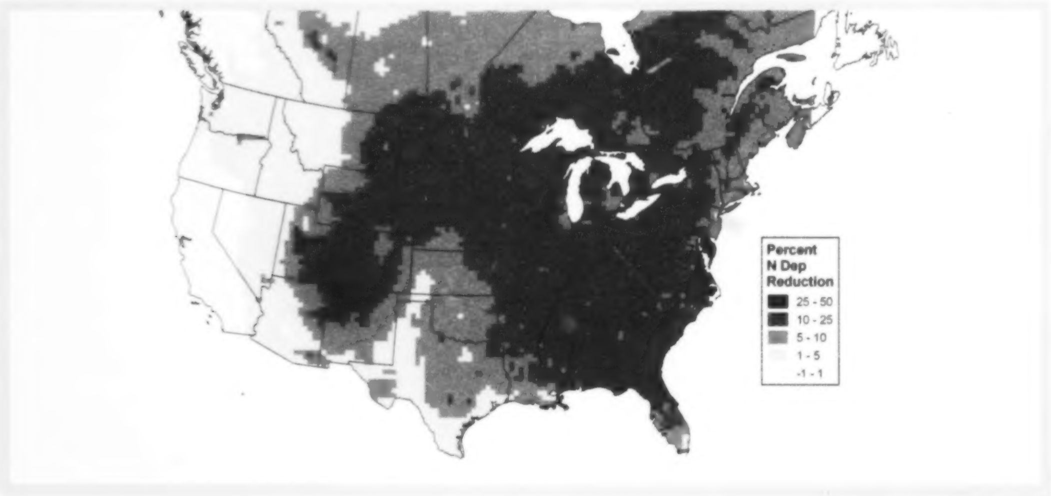


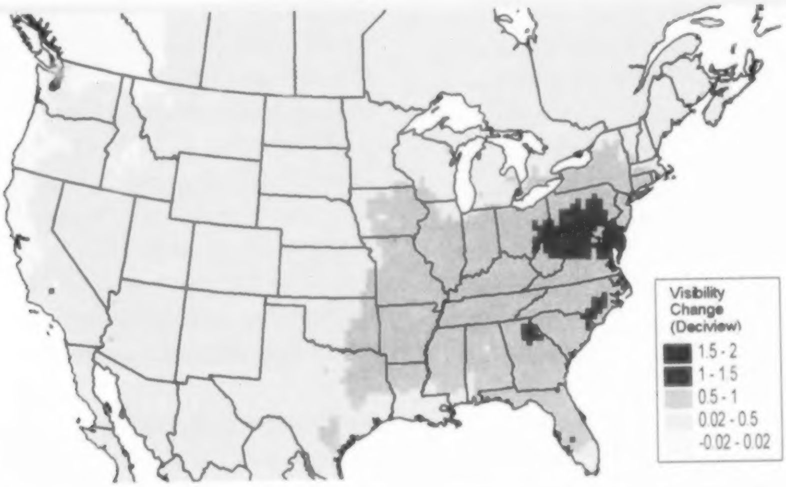
Figure H-22 Percent Change in Nitrogen Deposition with Emission Reductions under Illustrative Trading Scenario Compared to Base Case in 2020 (CMAQ)



H.4.5 Acidification: Sulfur Deposition

CMAQ modeling demonstrates in Figure H-21 that sulfur deposition will decrease across the eastern United States and Canada with an emission cap and cross-border trading scenario compared to the Base Case. Similar to the $PM_{2.5}$ concentrations presented above, total annual sulfur deposition is reduced across the sensitive receptors of eastern North America, notably in the receptor areas of upstate New York and eastern Canada. The whole domain experiences a reduction in 2010 (not shown) that expands and deepens in 2020 (Figure H-21). The largest reductions, from 30 to 65 percent, are projected to occur in the 2020 simulation in the midwestern states, the Appalachian area, and parts of New England in the United States, as well as in Ontario, Quebec, and the Maritime provinces. The emissions cap and cross-border trading approach produces significant broad

Figure H-23 **Absolute Change in Visibility (Deciviews) with Emission Reductions under Illustrative Trading Scenario Compared to Base Case in 2020 (CMAQ)**



regional reductions in sulfur deposition over the cross-border receptor area in eastern North America.

H.4.6 Acidification: Nitrogen Deposition

Modeling projections show in Figure H-22 that nitrogen deposition reductions will be seen across nearly all of the U.S. and cross-border Canadian region. In the United States, the Midwest, Southeast, and parts of the West see at least 10 percent reductions, while in Canada, southern Ontario and Quebec see 10 to 25 percent reductions under this illustrative scenario. The largest percent reductions, of up to 50 percent, are scattered in the U.S. Rocky Mountain West. The emissions cap and cross-border trading approach modeled here produces significant broad regional reductions in nitrogen deposition over the cross-border receptor area in eastern North America and the Colorado front range. As seen in the sulfur deposition results presented above, the reductions in the air quality indicator start in 2010, are domain wide, and are deepened and expanded geographically in the 2020 simulation (Figure H-22). Reductions in both sulfur and nitrogen deposition will contribute to reduced acid rain and improvements in acid-sensitive ecosystems.

H.4.7 Visibility

Visibility degradation is a significant concern in the United States, where the Regional Haze rule is driving long-term emission reductions, and in Canada, where Continuous Improvement/Keeping Clean Areas Clean provisions of the Canada-wide Standards are the basis for preventing air quality deterioration. In 2010 and 2020, visibility modeled improves noticeably (on the order of one deciview, which is a standard measure of visibility change, discernible to the typical eye), compared with the Base Case, if an emissions cap and cross-border trading scenario is considered (Figure H-23). Visibility improves as the concentration of airborne fine particles declines. Most significant improvement is observed in the mid-Appalachian area of the United States, with smaller improvements extending well into Ontario and across New England and eastern Canada. The emissions cap and cross-border trading approach produces significant broad regional improvements in visibility over the cross-border receptor area in eastern North America.

H.5 SUMMARY OF FEASIBILITY ANALYSIS AND TOOL DEVELOPMENT

The work undertaken for this feasibility study represents a number of important steps toward the understanding of cross-border air quality issues and the continued development of tools that will facilitate future discussions and analysis. The progress made in enhancing power sector and air quality modeling marks a significant milestone. The enhancements made to the IPM model are important for both countries as Canada and the U.S. pursue methods to reduce emissions from power plants to improve air quality, both separately and jointly.

The results of our preliminary analysis indicate that cross-border emissions cap and trading could provide opportunities for reducing emissions that have benefits in terms of air quality. The cap and trade framework can also provide cost savings because of the flexibility it provides to sources. The IPM model results have generally shown this to be true, and the modeling done in support of this study has reinforced these findings. The initial findings show that the U.S. and Canada can analyze in detail cap and trade scenarios to estimate significant impacts such as incremental cost, generation mix, allowance costs, and shifts of power generation between countries.

The air quality modeling results appear to be reasonable and consistent with observations made in the past; models were run successfully, producing technically sound results. The air quality modeling shows that broad emission reductions over a wide geographic region in both countries would provide improvements in air quality, including visibility and acid deposition, as well as health benefits. This work sets the stage for future modeling of the North American grid, operating in concert with an emissions cap and trading scenario that produces regional reductions for the air quality endpoints of interest.

The United States and Canada share common regional air quality problems. The successful development, enhancement, and use of tools that can analyze and model key aspects of different emission scenarios are apparent. Furthermore, the air quality modeling demonstrates significant air quality improvements and cost-effective reductions from applying an emissions cap and trading approach to SO_2 and NO_X emissions. The results presented here are a first step toward helping all interested parties better understand the implications of cross-border emissions cap and trading.

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